IMPERIAL OIL LTD.

COLD LAKE HEAVY OIL REVIEW

PRAIRIE/ARCTIC CORPORATE COMMITTEES

JULY 29, 1975

PROPRIETARY

Cold Lake heavy oil review, by Imperial Oil Ltd. Corporate Committees. n.p. Jul 29, 1975. (A-6184)

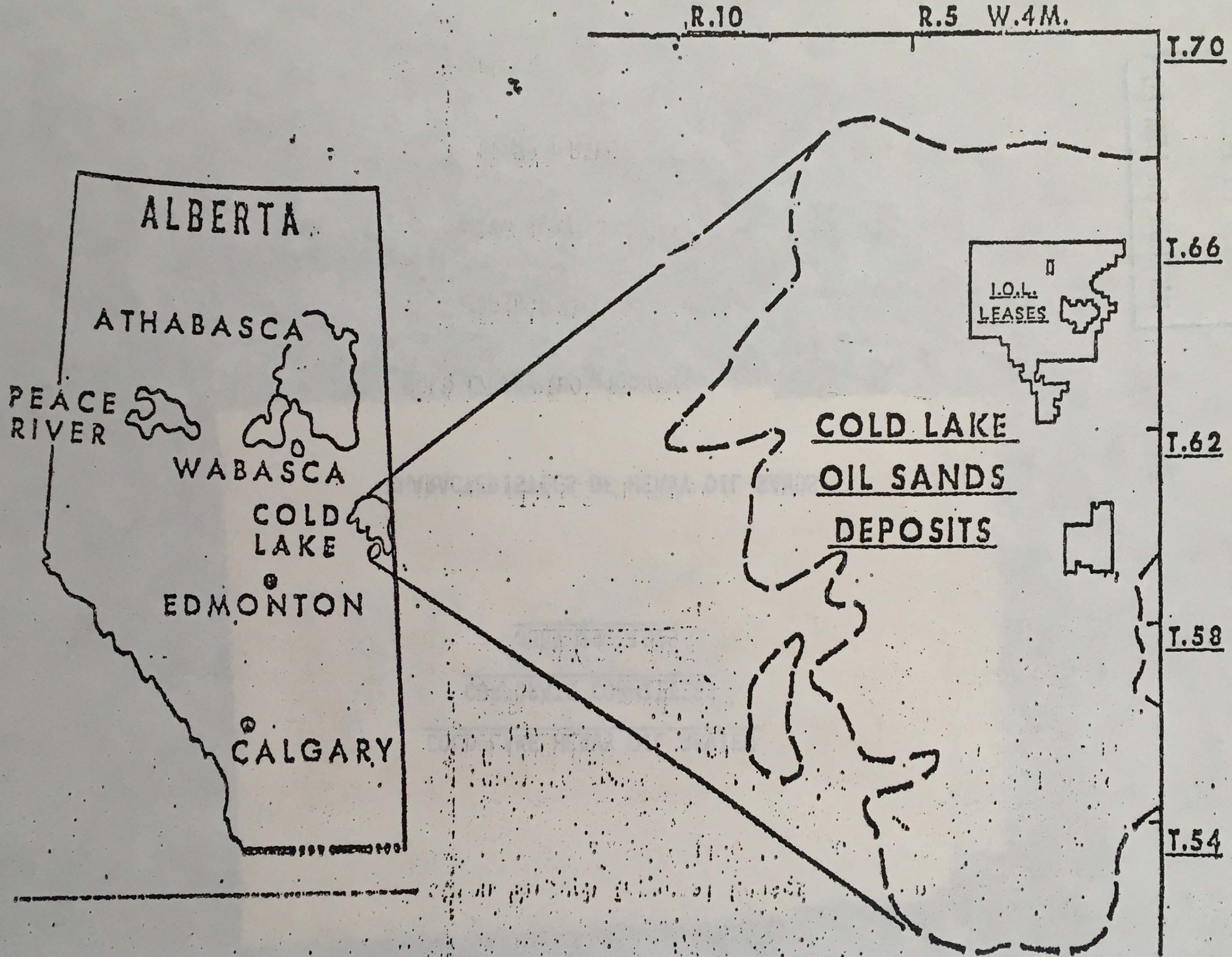
DATE	NAME OF BORROWER	ROOM

COLD LAKE PILOT PROGRAMS

- ETHEL PILOTS
- MAY PILOTS

- COLD LAKE PILOT PROGRAMS
  - ETHEL PILOTS
  - MAY PILOTS
  - LEMING PILOT
  - PLANS

COLD LAKE OIL SANDS



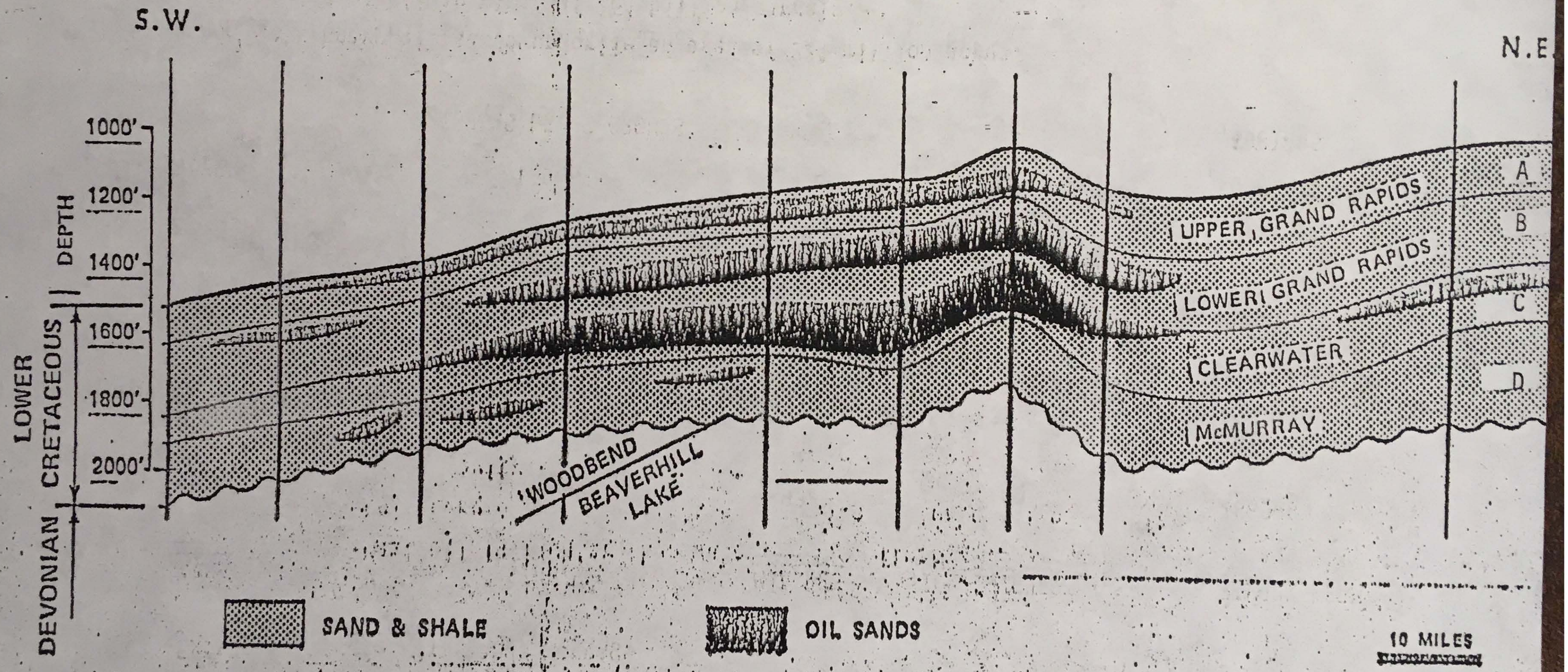
MAP - Heavy oil deposits outline -
Cold Lake - Wabasca - Peace River - Athabasca
Existing Imperial Oil Sands Acreage

AREA	RIGHTS *	M ACRES	IOL INTEREST - %	PRIMARY TERM
COLD LAKE	5 OSL	193.5	100	1989-90
ATHABASCA - IN-SITU	16 OSL	545.8	33 1/3	1982
	2 OSL	66.2	25	1982
	16 BSL	624.2	33 1/3	1981-82
- MINING	6 BSL	187.6	30	1980-81-82
PEACE RIVER	1 OSPP	44.8	50	1976
	4 P&NG LEASE GROUPS	85.8	100	1981-85

TEXT - Cold Lake heavy oil sands underlie an area of 2.4 million acres.
- ERCB estimates oil in place at 164 billion barrels.
- Imperial oil sands leases cover 193,500 acres.
- Imperial estimates oil in place in these leases at about 45 billion barrels.

* OSL - Oil Sands Lease
BSL - Bituminous Sand Lease
OSPP - Oil Sand Prospecting Permit
P&NG - Petroleum and Natural Gas

CROSS SECTION
COLD LAKE SANDS



CROSS SECTION

- Section through Imperial Leases as shown
- Depth of sand zones - 1100 to 1800 ft.

TEXT

- Four separate zones of sand deposition - Imperial designation - A, B, C, D, - ERCB designation - Upper Grand Rapids, Lower Grand Rapids, Clearwater, McMurray
- Variable rock properties in each zone
  - Sand thickness and vertical continuity
  - Occurrence of underlying water
  - Presence of gas
  - Grain size distribution - Permeability and porosity
  - Structure controlled by underlying formations - Devonian (Woodbend/Beaverhill Lake)
- Indications of fluid property variations
- Imperial activity concentrated on C-zone - 1500 - 1650 ft.

COMPARISON OF OIL PROPERTIES

	ATHABASCA	COLD LAKE "C" UNIT SAND	REDWATER D-3 CARBONATE
GRAVITY °API	8 - 10	10 - 12	35
SPECIFIC GRAVITY	1.03 - 1.01	1.0 - .99	.85
VISCOSITY AT RESERVOIR CONDITIONS, C.S.	100,000 - 3,000,000	100,000	3.1
SULPHUR %	3 - 5%	4.4	2.7

KEY FACTOR FOR RECOVERY IS VISCOSITY

OIL PROPERTIES COMPARISON (Physical Properties)

TEXT

-Most oil is lighter than water, - i.e. floats

-Cold Lake oil is, in fact, heavy - i.e. water can float on it

-API Gravity 10 - 12 degrees

Specific Gravity 1.0 - 0.99 - Essentially same as water

-Cold Lake oil is very thick - or viscous

-In the Reservoir the Viscosity is 100,000 times that of water

-i.e. Viscosity of 100,000 centistokes

-Cold Lake oil contains sulphur - average 4.4% by weight

Key Factor for Recovery is Viscosity

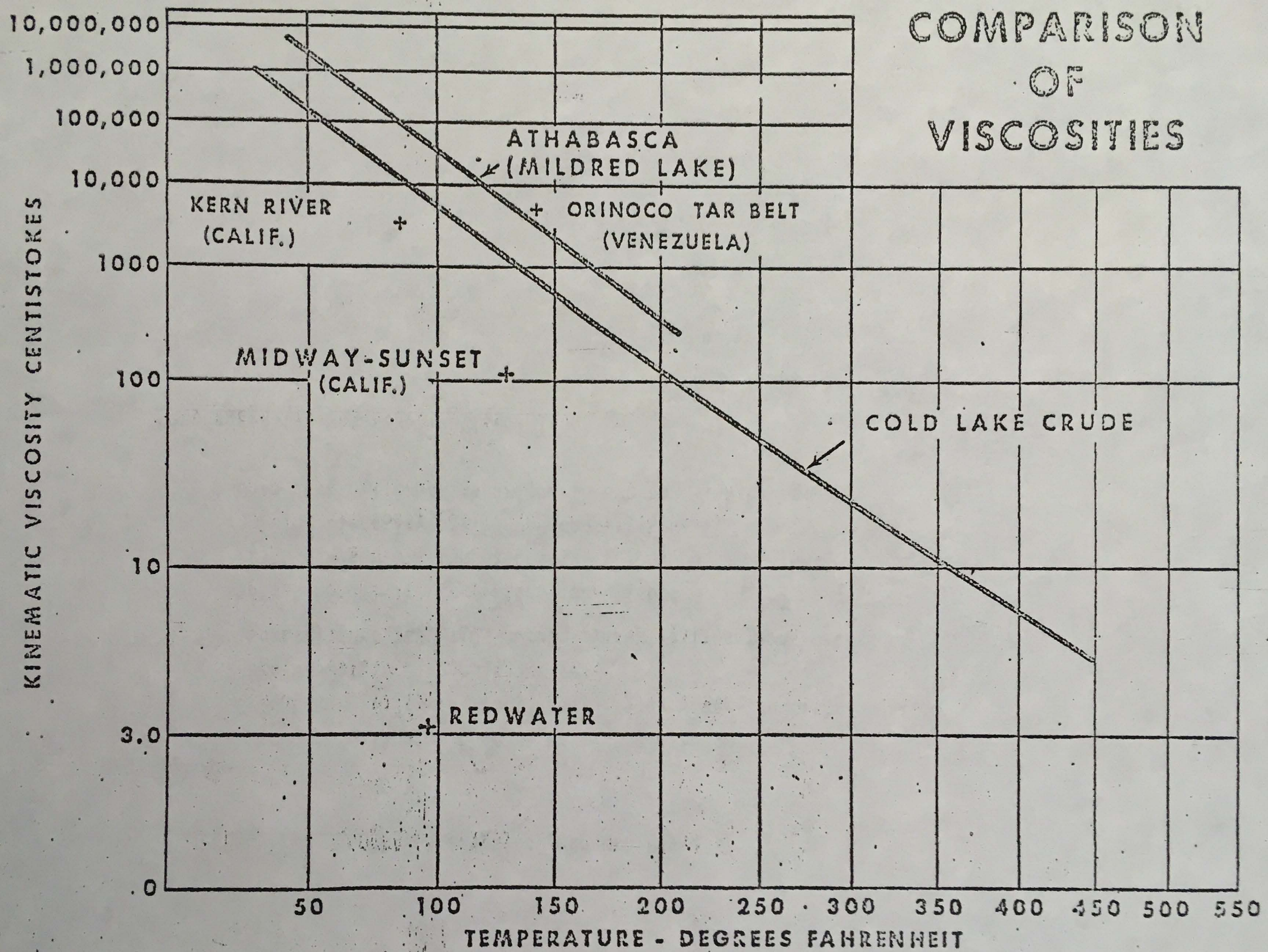

COMPARISON
OF
VISCOSITIES
10,000,000
1,000,000
100,000
10,000
1000
100
10
3.0
.0
KINEMATIC VISCOSITY CENTISTOKES
ATHABASCA
(MILDRED LAKE)
KERN RIVER
(CALIF.)
ORINOCO TAR BELT
(VENEZUELA)
MIDWAY-SUNSET
(CALIF.)
COLD LAKE CRUDE
REDWATER
50
100
150
200
250
300
350
400
450
500
550
TEMPERATURE - DEGREES FAHRENHEIT

CHART - Viscosity/Temperature Comparisons

- Note - Log - Log Scale -
  - Dramatic reduction with temperature increase
  - Comparison with Athabasca - other heavy oils
  - Comparison with conventional crude - Redwater type

TEXT - Recovery of Heavy Oil requires improving its ability to move within the reservoir

- Oil movement is dependent on reducing viscosity

Viscosity reduction achieved by:

- Heating alone - or
- Heating combined with - Natural Gas Injection and/or
  - Solvents and/or
  - Emulsifiers

DENSITY OF COLD LAKE OIL & WATER VS. TEMPERATURE

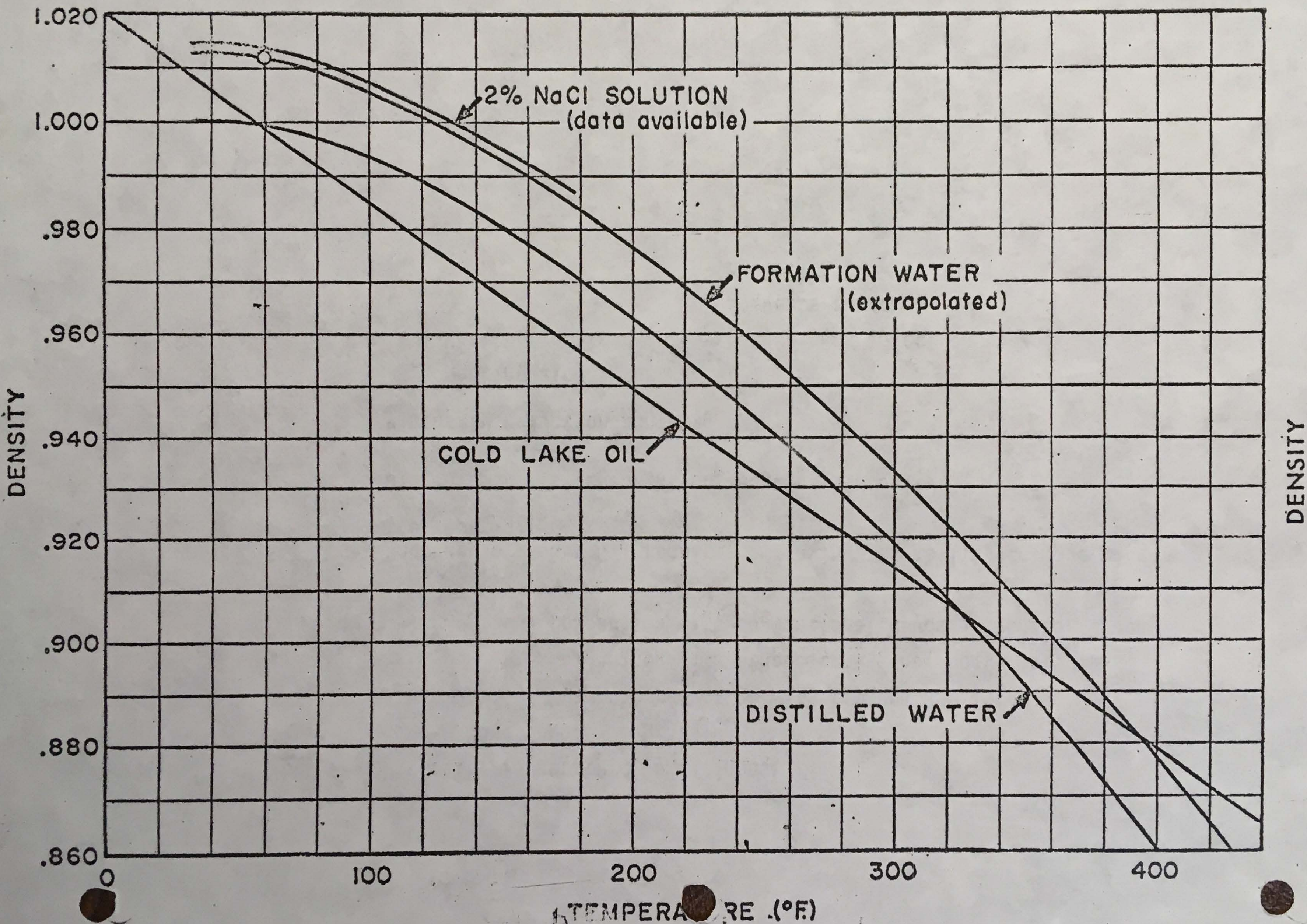


CHART - Density/Temperature Comparisons

- Note - Comparison of Cold Lake crude with water
  - Graph intersections versus temperature (60°F and 300°F)

TEXT - Effective oil-water separation requires gravity separation

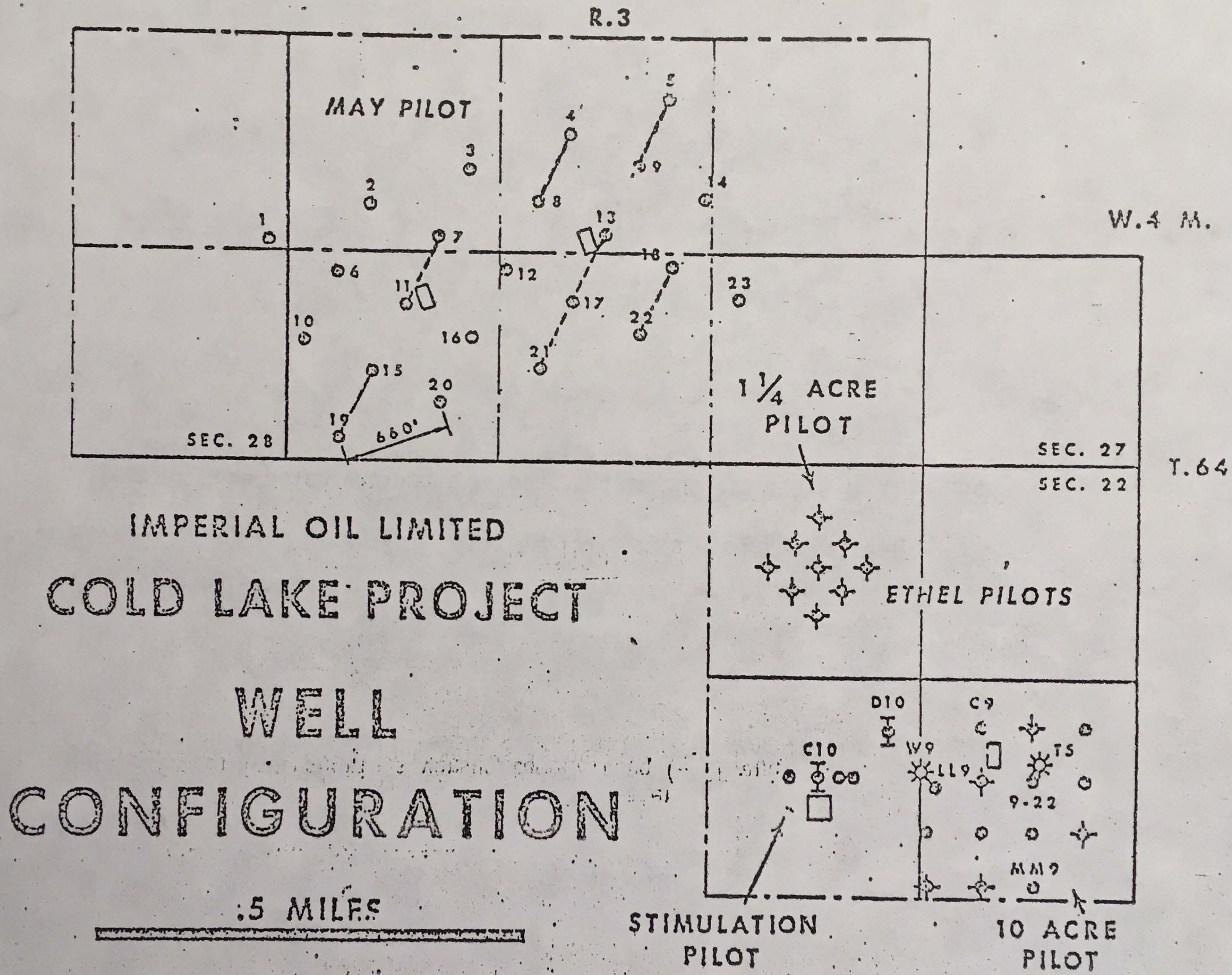
- Maximum Cold Lake oil-water density difference occurs between 150 - 230°F

- Oil-water separation equipment is operated at 200° to 220°F in the range of maximum density difference and lower viscosity

IMPERIAL OIL LIMITED

COLD LAKE PROJECT

WELL CONFIGURATION



REVIEW OF PILOT WORK AT COLD LAKE

MAP - Well Configuration

TEXT - 1. Ethel Pilots 1964 - 70

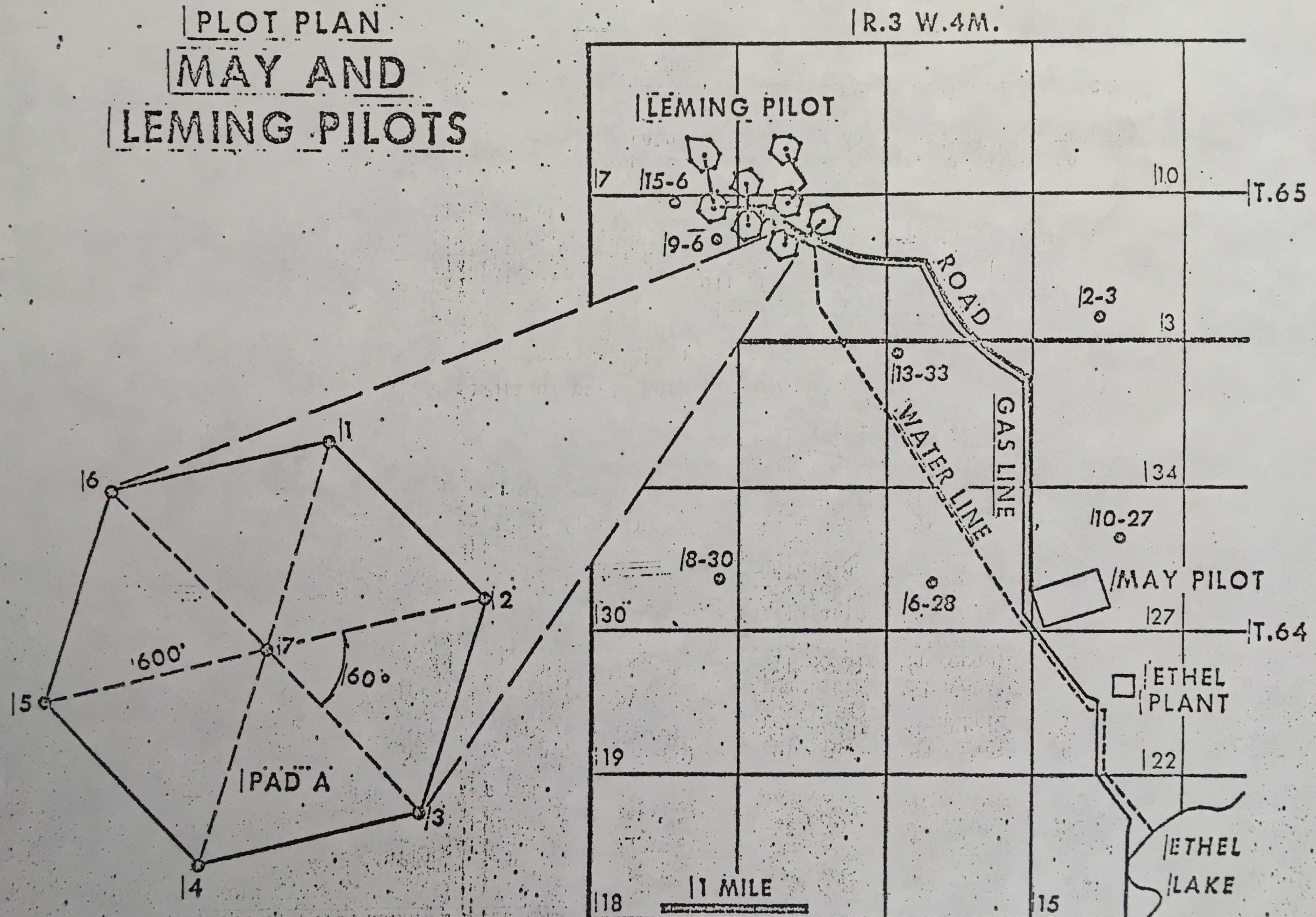
1. Stimulation Pilot (10-22) (4 wells) - Early injectivity tests and steam stimulation trials
2. 10-acre Pilot (9-22) (14 wells)
   - Steam stimulation evaluation
   - Well completion techniques
   - In-Situ combustion
   - Stimulation Aids (natural gas)
   - Stimulation with interwell communication
3. 1¼ acre Pilot (15-22) (9 wells)
   - Steam Flood Evaluation
   - Override flooding (gas cap)
   - Bottom water zone flooding
   - On-Trend flooding (NE-SW preferred flow direction)

As a result of pilot work to 1970, we concluded

- Satisfactory injection rates with high pressure
- A definite NE-SW preferred flow direction exists
- Underlying water is detrimental to stimulation recovery
- Gas injection benefits oil production
- Emulsion problems can be overcome with chemicals
- In-Situ combustion causes severe equipment damage and emulsion problems

2. May Pilot 1972 (23 wells)
   - To incorporate the best ideas, to date, and
   - To obtain high quality data leading to commercial operation
   - Continuation is necessary to evaluate long term performance

V



PLOT PLAN
MAY AND
LEMING PILOTS
R.3 W.4M.
LEMING PILOT
7
15-6
9-6
10
T.65
ROAD
2-3
3
13-33
GAS LINE
WATER LINE
34
10-27
8-30
6-28
MAY PILOT
30
27
T.64
ETHEL
PLANT
19
22
ETHEL
LAKE
18
1 MILE
15
1
2
3
4
5
6
7
600'
60°
PAD A

MAP - May and Leming Pilots

TEXT - Leming Pilot - 1975 (56 wells)

- To provide a better statistical basis for a commercial scheme based on steam stimulation, well productivity, oil recovery, operating cost
- To evaluate new drilling, completion, designs and operating concepts
- supply 4,200 BPD to Strathcona Refinery
- Capital cost - $15 million
- Operating cost - $1.9 million/yr. (1975)
- Consists of 8 pads of 7 wells each on 7.15 acre spacing
- A seven-spot pattern with 600 feet between wells
- 1,040 feet between wells in the direction of preferred fracturing
- 600 feet between wells across trend

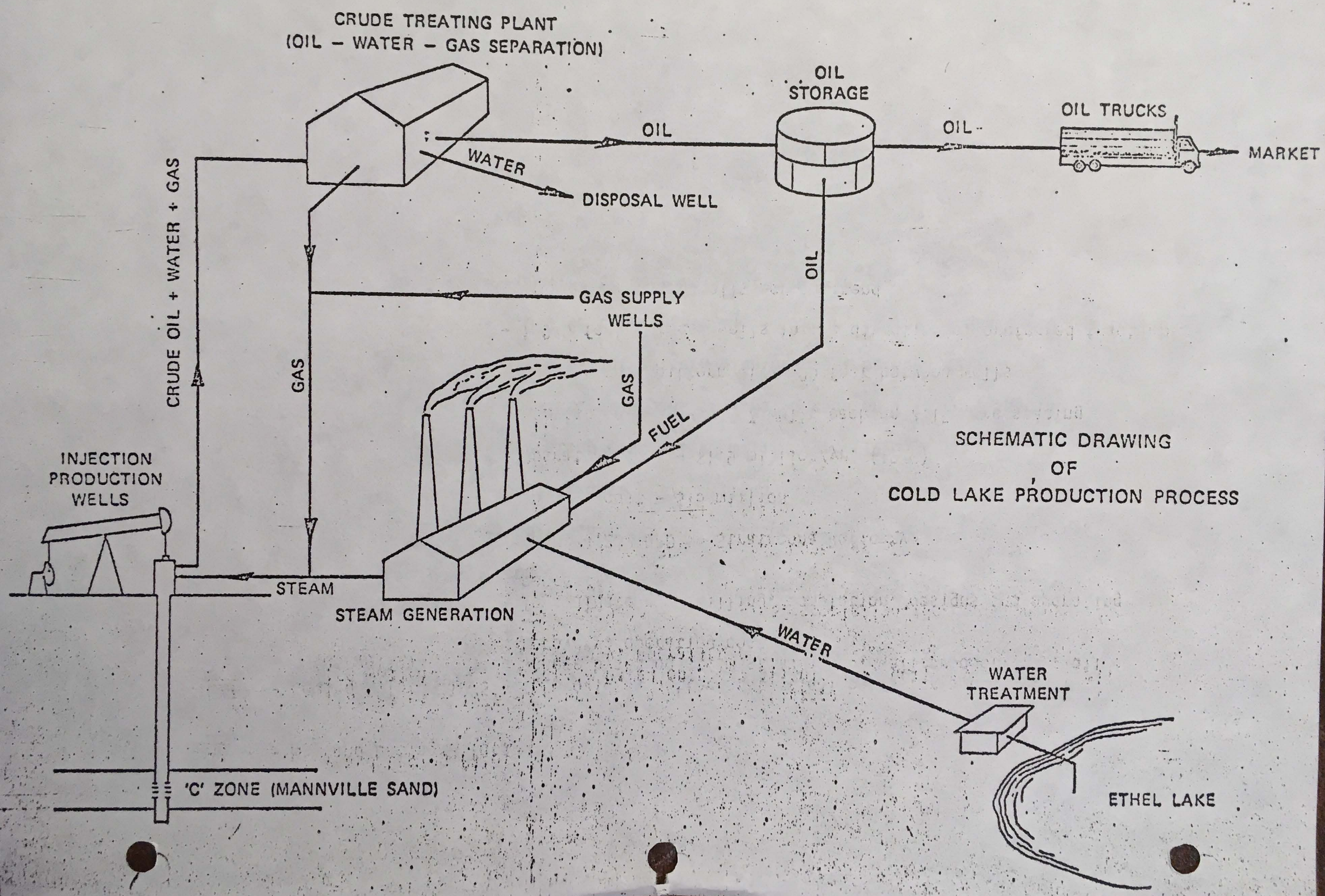

CRUDE TREATING PLANT
(OIL – WATER – GAS SEPARATION)
OIL
STORAGE
OIL TRUCKS
OIL
OIL
MARKET
WATER
DISPOSAL WELL
CRUDE OIL + WATER + GAS
OIL
GAS SUPPLY
WELLS
GAS
GAS
FUEL
SCHEMATIC DRAWING
OF
COLD LAKE PRODUCTION PROCESS
INJECTION
PRODUCTION
WELLS
STEAM
STEAM GENERATION
WATER
WATER
TREATMENT
'C' ZONE (MANNVILLE SAND)
ETHEL LAKE

CHART - Schematic of Pilot Facilities

TEXT - Refer to Process Flow Diagrams

Raw Water - treat and manufacture high pressure steam
- use produced oil, natural gas as fuel

Inject steam, natural gas into Production Wells

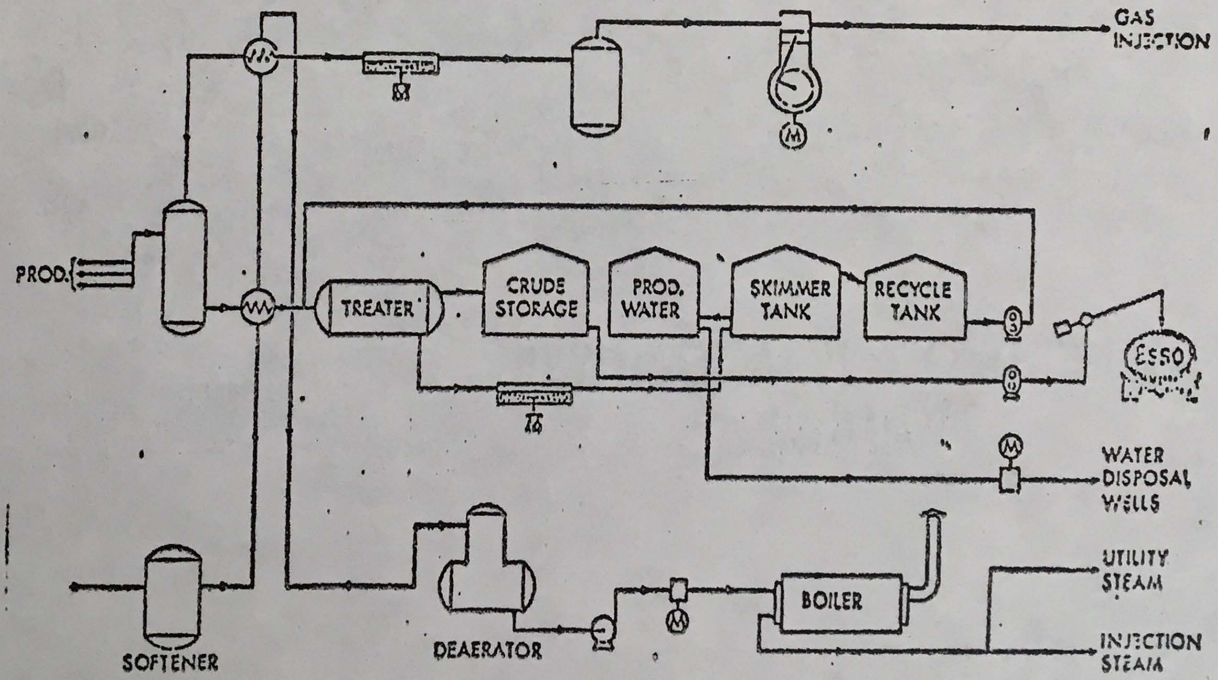
Place wells on production after suitable heating cycle

Separate oil, water and natural gas at Treatment Plant

Oil - to storage - truck to market
burn portion as fuel

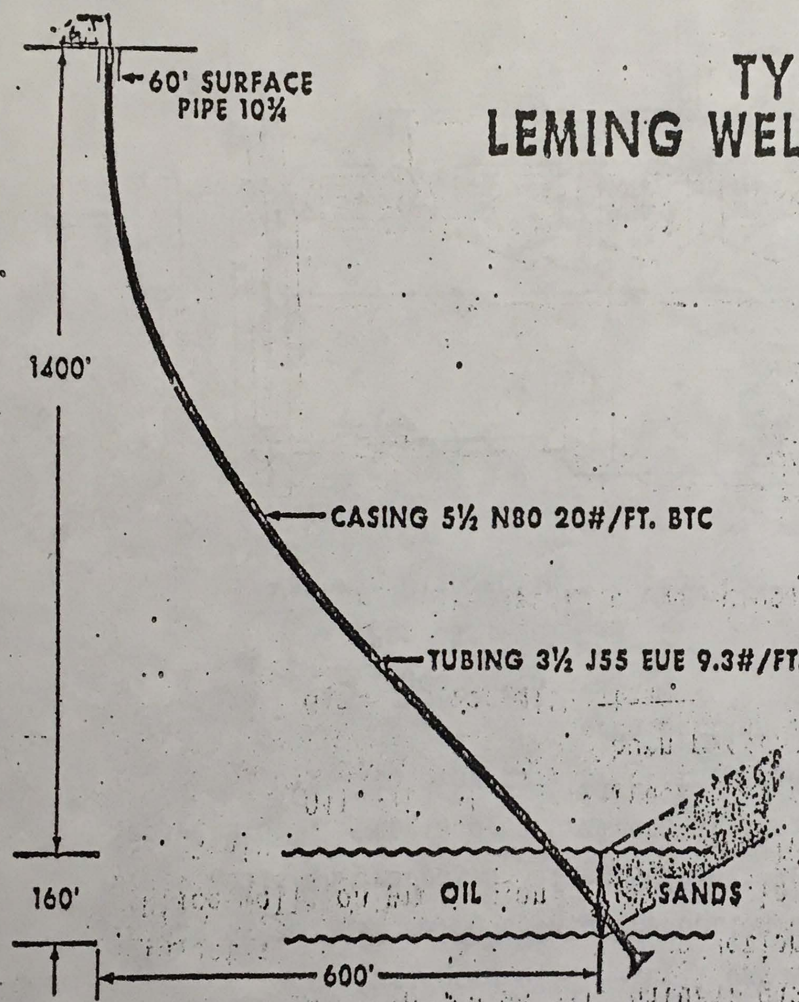
Gas - Inject with steam
Burn as fuel

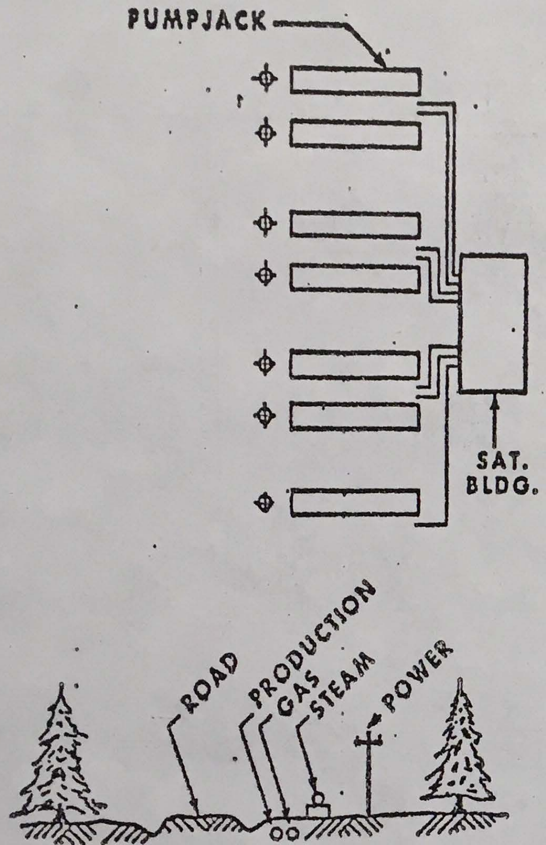
Water - Dispose into water bearing formation



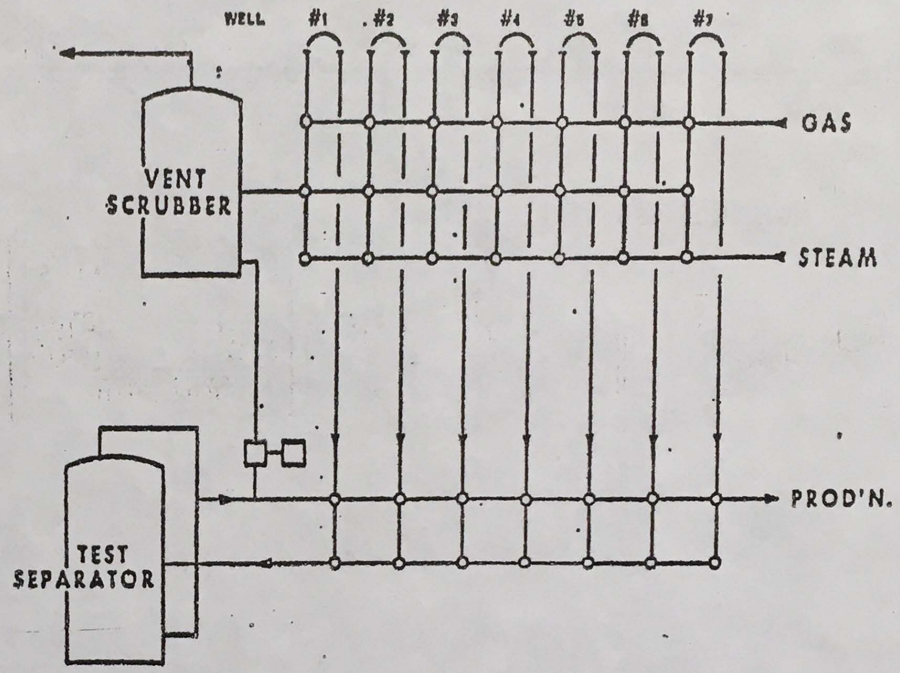
LEMING PLANT - SCHEMATIC

TYPICAL
LEMING WELL COMPLETION



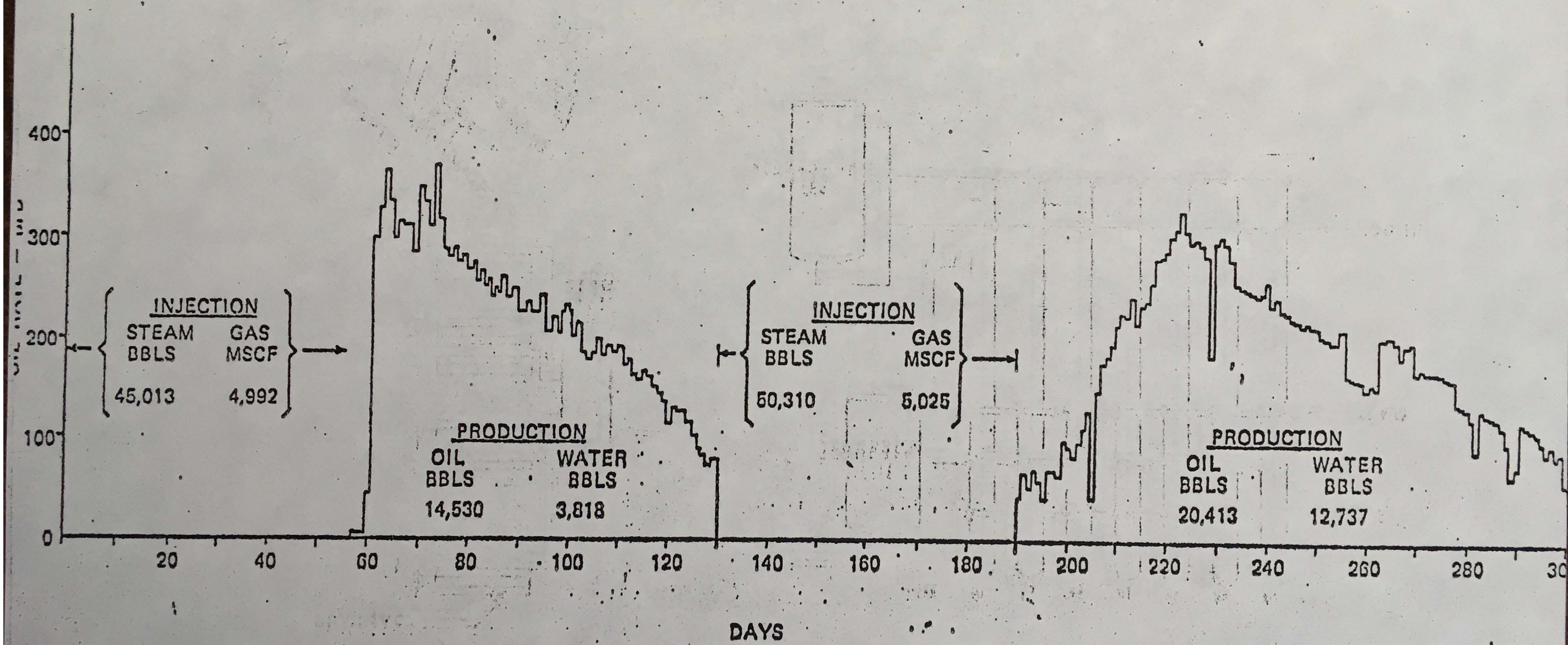


TYPICAL
LEMING SATELLITE
LEASE



SCHEMATIC OF LEMING SATELLITE

TYPICAL STEAM STIMULATION PERFORMANCE



RECOVERY AND RECOVERY RATE

CHART - Typical Steam Stimulation Performance

TEXT - Steam Stimulation - Present Process

- Injection/Production cycle performance dependent on:
    - Ability to distribute heat in the formation
- Amount of heat injected influences:
    - Rate of recovery
    - Ultimate Recovery - average well recovery of 100 M barrels by stimulation over 5 years
    - Stimulation Aid - Natural Gas Injection
    - Operating Cost
- Steam Displacement
- Involves establishing communication of the injected steam between wells through the formation. Continuous injection will displace the oil from the formation into producing wells. This technique should significantly improve recovery of oil in place.
- There are several unresolved parameters
    - Maximum well spacing dimension to permit communication
    - Optimum steam rate, production rate, well spacing
    - Water/gas zones

NEAR TERM PLANS

1975 - Drill and equip 14 additional wells at Leming to maintain deliverability in 1976.

- Continue data gathering and analysis of May Pilot Performance

- Obtain results, analyze Leming Pilot Performance

- Increased emphasis on thermal and production efficiency

- Screening studies and evaluation of alternate recovery processes

1976 - Drill 19 additional wells to maintain deliverability in 1977 and 1978

- Preliminary engineering for new recovery processes

1977 - Construct one or more new recovery pilots

SUMMARY

- Although costly, techniques for heavy oil recovery have been demonstrated

- Current pilot operations are directed at establishing

    - Production rate capability
    - Resource recovery
    - Improved thermal and production efficiency

- Continuing research will examine

    - New recovery method concepts
    - Laboratory studies
    - Field pilot demonstrations of new concepts

- Commercial schemes will be dependent on

    - Improved technology - requires lead times of 10 to 20 years
    - Higher crude oil prices
    - Reasonable sharing of revenues by Governments
    - Long term stability of Government Regulations
    - A reasonable profit motivation

Industry Review

Dominion Securities Harris

THE HEAVY OIL DEPOSITS OF WESTERN CANADA A FUEL FOR THE FUTURE GROWTH OF THE CANADIAN PETROLEUM INDUSTRY

OCTOBER, 1974

Maps

THE HEAVY OIL DEPOSITS OF WESTERN CANADA

A FUEL FOR THE FUTURE GROWTH OF THE CANADIAN PETROLEUM INDUSTRY

October, 1974

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SUMMARY AND RECOMMENDATIONS

The world energy balance has been seriously aggravated by the actions of the OPEC member countries during the past year which have brought the era of cheap energy from the vast oil reserves in the Middle East to an abrupt end. As North America strives for energy self-sufficiency, the development of the heavy oil reserves in Western Canada is especpted to be a priority item. Conventional crude oil production is peaking in Alberta while Saskatchewan and British Columbia fields have been declining for several years. In the Canadian frontiers the lack of a major discovery to date precludes significant production before the mid-1980's and further emphasizes the need for accelerating the development of the heavy oil deposits. While representation in an oil sands project, be it surface mining or in-situ, enhances the growth prospects for a Canadian oil company it can under no circumstance be considered a low risk venture or a guaranteed economic success. However, the oil sands have a most important role to play in the future of the Canadian Petroleum Industry and we recommend participation through either of the following four companies whose strong exposure in the oil sands areas, as detailed in reference Table IX, is complemented by an aggressive domestic and, in some areas, international exploration programme:

Imperial Oil
BP Canada
Husky Oil
Numac Oil and Gas

Obviously potential oil resources do not become supply available to the consumer, and earnings available to shareholders, unless they are developed. The timing of future crude oil supply will depend upon the rate at which the massive oil sands projects can be brought on stream as well as the level at which exploration proceeds in the frontier areas. This will be subject to numerous physical constraints as well as the business and geologic risks perceived by the oil companies whose judgements are based upon predictions of future crude oil prices, provincial and federal government and industry revenue sharing, stability of government regulations, prospective markets, etc.

There is no doubt that Canada will require significant crude oil supply additions in the near future: total demand is forecast at approximately 2.2 million barrels per day by 1980 while the available supply from conventional sources will have declined to about 1.5 million barrels per day. If Canada does not wish to be faced with a serious petroleum shortage by the mid-1980's and up to 60% dependent upon Venezuela and the Middle East countries, production must come from several new Canadian sources. This can only be realized through a continuation of the competitive enterprise system with a clear understanding of the role of the basic factors of price, market and share of reward between the public and the investor if the massive sums of capital and considerable technical expertise required to develop these new resources is to be available.

The federal-provincial confrontation over taxation of revenue from mineral resources, not only in Western Canada but also in the Atlantic provinces, must be resolved as soon as possible. This dispute has created major uncertainty in industry as well as considerable damage in the Canadian capital market which will be expected to raise a significant portion of the capital funds required. Investor confidence in the natural resource sector has been seriously eroded by the intrusion of various levels of government during the past year and it must be restored if Canada is to realize the potential of its vast undeveloped natural resources.

Of particular importance to the future of the oil sands will be the Alberta Government's position paper on oil sands development which is expected within the next month. This document should spell out the ground rules for development so that serious problems regarding the environment, construction and production may be avoided. Although several new projects have been approved by the Alberta Energy Resources Conservation Board, only the Syncrude plant has received the final approval from the Alberta Cabinet. Approval came after lengthy negotiations which led to the pioneering 50% profit sharing agreement as well as an option for the government to acquire a 20% working interest in the project upon completion. Similar agreements will have to be reached for all future oil sands projects and initial developments suggest that a 50% Canadian participation may be a government goal.

J. D. McCleary, P. Geol.
October, 1974.

INTRODUCTION

Heavy oil occurrences in Western Canada fall into two broad classifications: oil sands deposits and Lloydminster type accumulations, depending upon the characteristics of the crude they contain. This report assesses the potential of the four principal oil sands deposits in Alberta, namely Athabasca, Cold Lake, Peace River and Wabasca plus the Lloydminster area. The Alberta Energy Resources Conservation Board (Board), defines oil sands as those having a "highly viscous crude not recoverable in its natural state through a well by ordinary production methods". This hydrocarbon material is designated as bitumen and has a napthene base, is black in colour and contains a characteristically high percentage of sulphur, nitrogen and base metals. Relative to the conventionally produced crude oils, it is heavy, averaging about 10 degrees API gravity throughout the Athabasca deposit. The gravity of the bitumen in the Peace River deposits to the west is similar while in the Cold Lake area, the heavy hydrocarbons are transitional in properties between the bitumen of the Athabasca oil sands and the heavy crude oil of the Lloydminster area of the south. See reference Table I for a descriptive summary of the various deposits.

The total proved initial in place reserves of bitumen are estimated to be 895 billion barrels; however, the Board considers that the ultimate in place reserves from the presently delineated oil sands deposits in Alberta will approach 1,000 billion barrels. In the Board's opinion, after reviewing possible recovery techniques and deposit characteristics, the ultimate potential recoverable reserves of crude bitumen at an average recovery of 33% are approximately 330 billion barrels, and of synthetic crude at 75% volume conversion, close to 250 billion barrels.

The importance of the oil sands as a future petroleum source for Canada and the United States cannot be over-emphasized at this time. Even the estimated 26.5 billion barrels of proven reserves which are recoverable via open-pit mining operations (ignoring the total 250 billion barrels potentially recoverable with insitu processes) are significant in the context of known worldwide oil accumulations as illustrated below:

Region	Recoverable Conventional Reserves	Recoverable Synthetic Reserves	Potential Recoverable Synthetic Reserves
	(Billion Barrels)		
North America			
Established Areas	51		
Alberta Oil Sands		26.5	250
Oil Shales		N.A.	80
Central & South America			
Established Areas	32		
Orinoco Heavy Oil Belt			200
Western Europe	16		
Middle East	350		
Africa	67		
Asia - Pacific Rim	16		
Soviet Bloc & China	103		
Total	635	26.5	530

There are two basic and distinct methods for recovering bitumen from oil sands deposits: open pit mining and in-situ processes which must be used where overburden thickness exceeds about 200 feet. Open-pit mining of the oil sands coupled with hot-water extraction of the bitumen is presently in commercial use at the Great Canadian Oil Sands operation and a similar procedure will be used by Syncrude Canada, Shell, Petrofina and Home Oil. This method consists of the following major steps:

1. Land clearing, muskeg and overburden removal.

2. Mining of oil sands via bucket wheel excavator or dragline.

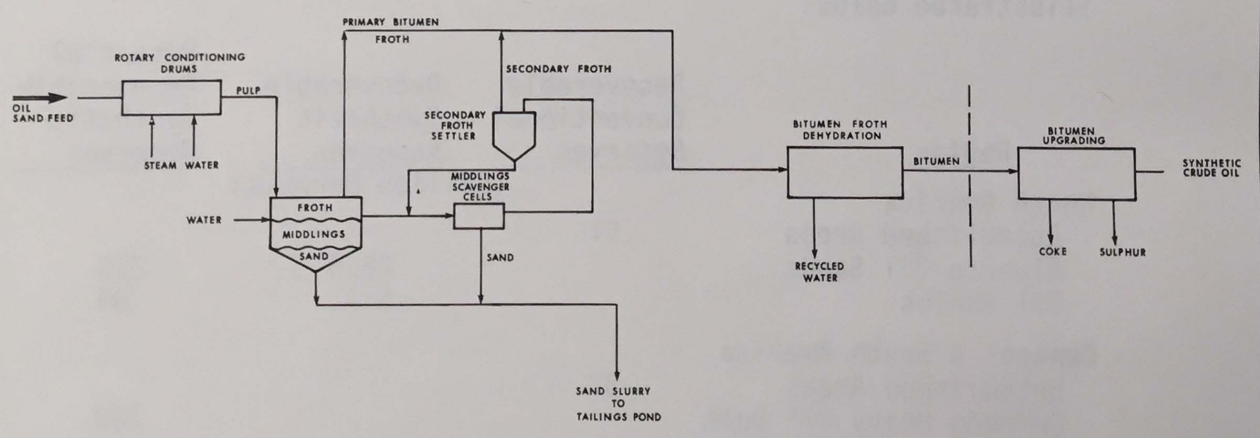
3. Transporting sands by conveyor systems or trains to bitumen extractor facilities.

4. Separation of bitumen from sand by the hot water flotation process. The bitumen is recovered, dried and ultimately refined into synthetic crude oil.

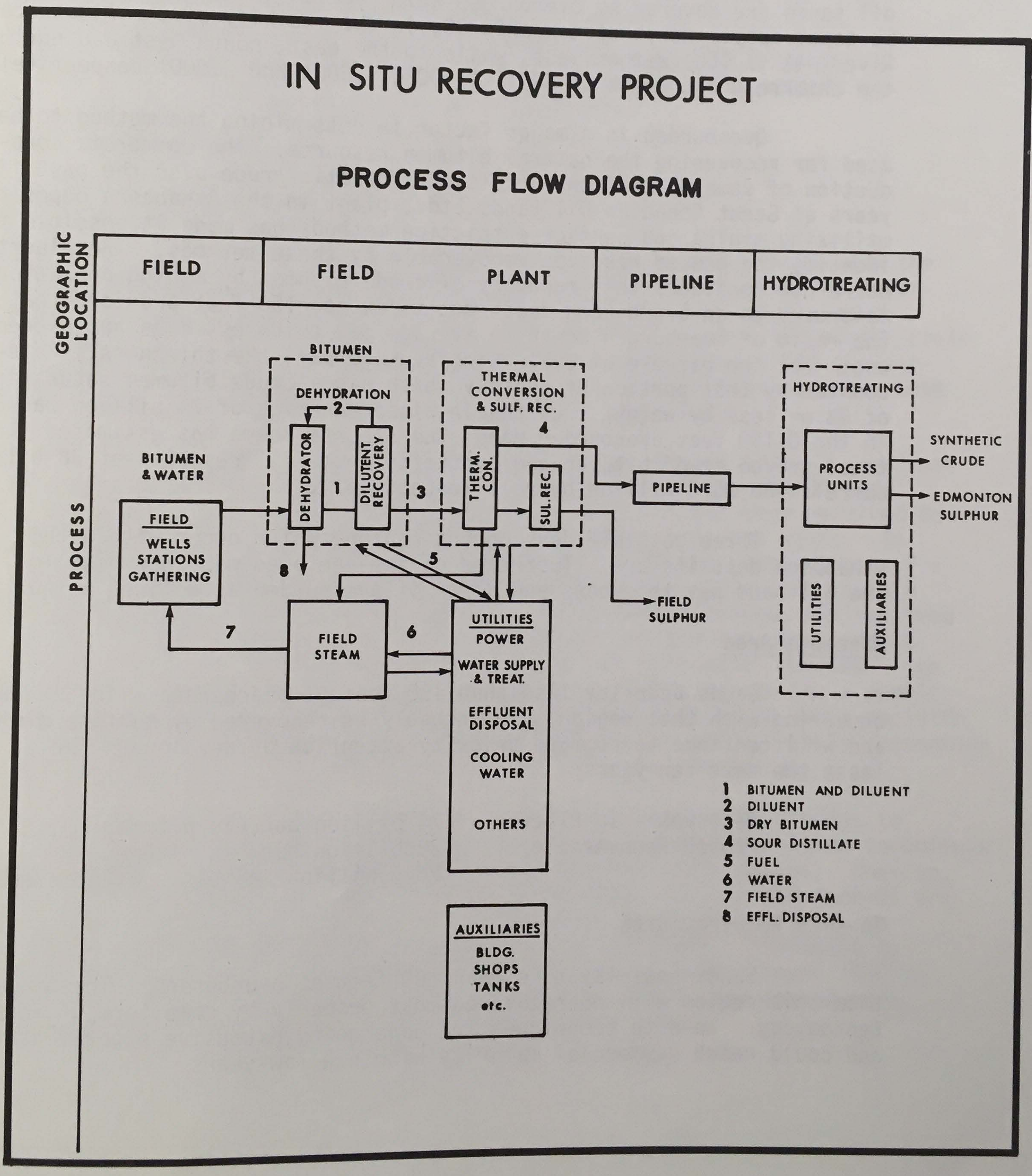
5. Transporting residual sand water emulsion to settling ponds and then moving sand into mined out area.

6. Reclamation of the mined out area to return it to near its natural state.

OPEN PIT MINING PROJECT
PROCESS FLOW DIAGRAM



The overburden thickness in the case of a large portion of the Athabasca deposit and the entire Cold Lake, Peace River, Wabasca and Lloydminster deposits is too great for mining and thus the bitumen must be extracted without removing the sand or overburden. This is achieved by different types of "in-situ" processes. None of the currently developed processes are considered to be commercial at present. In-situ extraction may involve non-thermal techniques, principally the addition of a dilutent to the reservoir, or thermal techniques involving hot water or high pressure steam injection into the reservoir, or thirdly combustion or nuclear explosion in the reservoir. These methods are principally directed towards reducing the viscosity of the bitumen or heavy crude in order to cause it to flow to production wells where it can be mechanically pumped to the surface. The bitumen is similar to that produced by the open-pit mining and hot water extraction technique, and is subsequently upgraded to a marketable product.



ATHABASCA OIL SANDS DEPOSIT

General Comments

This deposit underlines 9,000 square miles in northeastern Alberta and contains some 626 million barrels of crude bitumen in place or 70% of the total evaluated oil sands reserves. Except for localized out-crops occurring along the Athabasca River and its tributaries, the oil sands are covered by overburden which varies in thickness according to topography. North of township 90, in the vicinity of the Athabasca River, it is 100 feet or less, while to the east, south west and north, the thickness increases to 600', 1,500', 1,600' and 2,000' respectively.

Overburden is a major factor in determining the method to be used for recovering the natural bitumen resource. The commercial production of some 72 million barrels of synthetic crude over the past five years at Great Canadian Oil Sands Ltd., plant in the Athabasca deposit utilizing mining and surface extraction methods has made it possible to identify the proved reserves recoverable by these methods. The Alberta Board now considers that recovery of crude bitumen by mining operations is proved to an overburden depth not to exceed 150 feet provided that the ratio of overburden depth to average pay thickness does not exceed one. For the purpose of evaluating average pay, the thickness is discounted by that portion of the pay which has a crude bitumen saturation of 5% or less by weight. Of the in-place reserves of 74 billion barrels in the 0-150 feet overburden range the Alberta Board has estimated the total proved crude bitumen and synthetic crude oil reserves at 38 billion barrels and 26.5 billion barrels respectively.

Three possible development regions which occur within the Athabasca deposits are illustrated on the enclosed map according to the oil sand pay thickness and depth of overburden as defined below:

Mineable Area

Sands underlay less than 150 feet of overburden. The bitumen occurring with this region will probably be recovered by surface mining and will continue to command priority attention by developers for at least the next ten years.

Reserves - In Place	: 74 billion barrels bitumen
Proved Recoverable	: 38 billion barrels bitumen
	26.5 billion barrels synthetic crude

In-situ Recovery Area

Sands underlay more than 500 feet of overburden. The bitumen from this region will be recovered most probably by some form of in-situ technology. In-situ techniques are undergoing extensive experimentation and could reach commercial maturity within a few years.

Reserves - In Place : 417 billion barrels bitumen
Potential Recoverable : 83 billion barrels bitumen
58 billion barrels synthetic crude

Future Development Area

Sands underlay more than 150 feet and less than 500 feet of overburden. Developments in this region deferred pending the evolution of an appropriate recovery method.

Reserves - In Place : 135 billion barrels bitumen
Potential Recoverable : Not recoverable with present technology.

Recent Developments

Mineable Area

Commercial development of the Athabasca deposit has been the aim of several companies during the past 50 years. In 1930 the International Bitumen Company became the first firm to exploit the sands commercially which resulted in the extraction of several thousand barrels of tar. In 1936 and 1937 Abasand Oils Ltd. constructed a 250 ton-per-day and a 400 ton-per-day separation plant near Fort McMurray, but both plants were destroyed by fire shortly after completion.

The only commercial operation at the present time is the Great Canadian Oil Sands Limited plant which produces between 50,000 and 52,000 barrels per day at peak capacity. Approval has been received to expand this to 65,000 barrels per day within the next two years. In addition, Syncrude Canada Ltd. is proceeding with the construction of a 125,000 barrel per day plant scheduled to commence operations in late 1977 or early 1978. A third company, Shell Canada Limited, has received approval from the Board for a 100,000 barrel per day recovery project. The decision is subject to confirmation by the Provincial cabinet. The application of a fourth group operated by Petrofina Canada for a permit to construct a 122,500 barrel per day plant has been heard and a decision is expected later this year. Home Oil and Alminex are currently presenting their plans for a 103,000 barrel per day plant to the Board.

Several other groups are continuing feasibility studies to examine various mining, extraction, upgrading and transportation techniques for the recovery of bitumen reserves underlaying their leases. Chevron, Union, BP Canada, Can-Amera (Shaheen Resources), Ashland and Amerada are believed to be among those with sufficient mineable ore reserves to supply a 100,000 barrel per day synthetic crude plant. According to some observers the second generation plants to be built around 1980 in the oil sands may have a capacity of 200,000 barrels per day or more.

Details of the Great Canadian Oil Sands mining operation which has been on stream since mid-1967 as well as the proposed projects by Syncrude Canada Ltd., Shell Canada - Shell Explorer, the Petrofina Canada group and Home Oil - Alminex are summarized in Reference Table II.

In-situ Area

Present technology indicates that overburden depths should be at least 500' in order to safely contain the reservoir pressures generated by an in-situ recovery scheme. Reserves in the 500 feet plus category total about 417 billion barrels, and thus some 135 billion barrels or 21% of the in place reserves which fall into the 150-500 foot overburden depth interval are apparently undevelopable pending the evolution of an appropriate recovery method.

A major experimental in-situ test has been operated for several years by Amoco Canada in the Gregoire Lake on Crown Lease No. 76. The Company has invested about $9 million and plans to spend an additional $13 million on its field programme. Amoco refers to its process as the COFCAW process, meaning "Combination of forward combustion and waterflood". The detailed results of the tests are confidential; however, oil recoveries as high as 40% have been recorded from experimental models utilizing this process. A second experimental project is operated by Texaco Exploration on Lease No. 51, immediately south of Fort McMurray.

In 1963, Shell Canada made application for approval of an in-situ method of recovering the bitumen underlying Crown Lease No.'s 26, 42, 53 and 45. Initial operations were scheduled to begin on Lease No. 53 which Shell estimated contained total reserves in producible sands of 4.4 billion barrels of bitumen while in the whole of its leases, reserves were estimated at 11.4 billion barrels. Results of a pilot programme utilizing a technique for creating horizontal fractures at the base of the oil sands followed by injection through a central well of heated aqueous alkaline solutions and steam resulted in up to 30% recovery of the original oil in place. The proposed commercial project, subject to a successful two year scaled down initial stage operation, would be designed to produce 97,000 barrels of synthetic crude per day from 130,000 barrels of raw bitumen. The applciation was turned down by the Board at that time because of concern that the conventional crude oil industry in Alberta would lose some of its markets to these new sources of supply. Ten years later the situation has completely turned around with conventional oil production now unable to meet market demands. Shell, however, has not re-applied for approval of this project. Apparently, the Company feels that its mining project on Lease 13 is more economical at this time.

In the southern portion of the Athabasca deposit as shown on the enclosed map Numac Oil and Gas has established the presence of a thick sand body which the company estimates contains in place bitumen reserves of 20 billion barrels or more. Evaluation drilling is continuing on this property and an in-situ recovery pilot plant may be operational by the end of 1975.

COLD LAKE OIL SANDS DEPOSIT

General Comments

The Cold Lake oil sands deposit illustrated on the enclosed map is overlain by about 1,500 feet of overburden and covers an area of almost 3,500 square miles in east central Alberta. With this depth of overburden the bitumen must be recovered via in-situ techniques. Total proved in-place reserves are estimated by the Board to be 164 billion barrels, none of which as yet are classed as proved recoverable. However, using an overall 20% bitumen recovery factor and a 70% conversion, the deposit could yield up to 33 billion barrels of bitumen and 23 billion barrels of synthetic crude oil. The mode of occurrence of the bitumen reserves has been classified into three broad categories as defined below:

Massive or Rich

Areas where more than two-thirds of the total oil sand occurs in one or more thick zones, i.e. greater than 40 feet.

Reserves - In Place :	65 billion barrels bitumen
Potential Recoverable :	13 billion barrels bitumen
	9 billion barrels synthetic crude

Intermediate

Embraces those areas where one-third to two-thirds of the total oil sand exists in thick zones.

Reserves - In Place :	83 billion barrels bitumen
Potential Recoverable :	16.6 billion barrels bitumen
	11.6 billion barrels synthetic crude

Dispersed or Lean

Encompasses the areas where less than one-third of the total oil sand occurs within thick zones.

Reserves - In Place :	16 billion barrels bitumen
Potential Recoverable :	3.2 billion barrels bitumen
	2.2 billion barrels synthetic crude

The Board employed oil saturation cut-off limits as well as the thickness criteria above to exclude bitumen considered to be unrecoverable by any foreseeable technology. We expect development will concentrate in the massive and to a lesser extent the intermediate saturation areas which are most attractive for a secondary recovery scheme at this time. Generally speaking, the massive sand areas have

a production potential of 8-9,000 barrels per day per section (640 acres), as compared to 3-4,000 barrels per day per section in the intermediate saturation areas.

Recent Developments

Since late 1964, Imperial Oil has been engaged in experimental in-situ operations on its Cold Lake properties which contain estimated in place reserves of bitumen in the 30 billion barrel range. Almost all of the effort has been devoted to trials of steam recovery techniques. The work was discontinued briefly in 1970-71 however, but was reactivated in the fall of 1971, when Imperial built the May pilot with 23 wells spaced about 500 feet apart on a five acre spacing pattern. Approximately half of the wells are utilized as injectors at any one time while the balance are producing about 1,500 barrels per day of bitumen which is trucked to Lloydminster for sale. The company is now constructing a new facility called the Leming pilot on a tract of land about four miles from the May site. When this new 56 well test comes into full production it will be producing as much as 4,000 barrels per day, excluding about 1,200 barrels per day which would be utilized as fuel for steam generation. This latter pilot will cost approximately $14 million and come on stream late in 1974. Imperial feels that a two to three year test period will be required to determine if a commercial operation using this technique is feasible.

Several other operators have conducted experimental projects at Cold Lake in the past including BP Canada which is throught to have the most attractive acreage spread after Imperial. The company estimates that bitumen reserves in place under its property are in the order of seven billion barrels. Great Plains, Yellowknife Bear, Mobil Oil, Texaco Exploration, Amoco and Amerada Hess have also investigated thermal in-situ recovery techniques in this deposit. The Great Plains - Yellowknife Bear team with interests of 35% and 65% respectively may have their third experimental steam injection project underway by the summer of 1975. The size is still under consideration, with in-place bitumen reserves thought to be in the range of 700 million barrels. Murphy Oil has acquired interests in several acreage blocks in the south Cold Lake area and is installing an experimental thermal steam flood this year.

Union Texas of Canada (a division of Allied Chemical Corporation) plans to produce bitumen from a depth of about 1,400 feet with permitted maximum production set a 1,000 b/d although actual production is expected to run around 500 b/d. Included in the programme are sixteen wells plus construction of a thermal plant.

Canadian Industrial Gas and Oil will evaluate its oil sands lease No. 60 in the Cold Lake deposit jointly with Marubeni Corp. and Fuyo Petroleum Development Corp. of Japan. A study will be conducted to determine the feasibility of in-situ production from this property which could have in place bitumen reserves of 2 billion barrels. The

estimated $20 million evalaution programme to be operated by CIGOL will consist of drilling 50 exploratory wells by June, 1975, engineering studies and pilot operations. The Marubeni Group will earn a 50% interest in the lease if it completes $16.5 million of the total expenditures. CIGOL has already reserved some key pieces of equipment for a prototype production facility that would be based on the pilot plant, assuming it is successful, and would increase the experimental output of 500 barrels per day to 2,000 barrels a day of oil after 1978.

The pilot projects now under construction are expected to show what the wells can produce on a sustained basis and permit a realistic evaluation of the risks involved before undertaking a large scale commercial operation. This would probably see daily production rates of up to 100,000 barrels achieved through a number of separate recovery systems of between 25,000 and 50,000 barrels a day capacity. At the present time it appears that several more years of experimentation are required before any decisions are made and it will be the early 1980's before any major projects could be on stream.

PEACE RIVER OIL SANDS DEPOSIT

General Comments

The Peace River oil sands deposit illustrated on the enclosed map underlies approximately 1,800 square miles in north central Alberta, approximately 250 miles northwest of Edmonton. Proven in-place bitumen reserves have been estimated by the Board at 50 billion barrels, none of which are considered as proved recoverable. However, at a 20% bitumen recovery via an in-situ scheme and 70% conversion it could yield up to seven billion barrels of synthetic crude.

Recent Developments

Considerable field testing and laboratory work by the team of Shell Canada and Shell Explorer Limited, (a subsidiary of Shell Oil Company), has resulted in the development of a steam-based recovery process which could provide an efficient means of crude bitumen recovery from the Peace River accumulations where they hold some 160,000 acres of oil sands leases. The new process, which has been tailored to the reservoir situation at Peace River where a thin relatively high-water saturation zone underlies the thick bitumen zone, involves a conventional steam drive approach until steam breakthrough, followed by pressurization and depletion cycles to recover the formation bitumen. The pilot test currently being designed is expected to be in operation by mid-1976 at an initial installation cost of some $33 million with total cost for a nine year run expected to amount to $85 million. For the pilot configuration of the pressure cycle steam drive process a pattern of seven 7 acre-7

spot has been selected. The operation calls for 48 wells: 24 oil production wells, 7 steam injection wells, 12 pressure and/or temperature observation wells, 2 fuel gas wells, and 3 water disposal wells. Maximum oil production is expected to be about 250 barrels daily per producing well while recoveries of between 40% and 70% of the oil-in-place are anticipated based on model studies. Confirmation of the subsurface process viability in the test combined with an improved economic and political climate could lead to the commitment to a commercial venture of some 100,000 barrel per capacity in 1982 and a full-scale project on stream in 1985.

WABASCA OIL SANDS DEPOSITS

General Comments

The Wabasca oil sands deposit illustrated on the enclosed map underlies approximately 1,600 square miles immediately west of the large Athabasca accumulation. Again these deposits are too deep for recovery by mining. Proved in-place bitumen reserves are estimated to be 54 billion barrels, none of which are considered as proved recoverable at this time. However, a 20% bitumen recovery and 70% conversion would yield about seven billion barrels of synthetic crude oil.

Recent Developments

Exploration drilling and geological evaluation programmes have defined prospective boundaries of this deposit although no major in-situ test programmes have been undertaken to date. The Board has given approval to Gulf Oil Canada for recovery of bitumen and other products from the deposit through a scheme which involves the drilling of two wells about 850 feet deep. Steam will be injected into both wells at the maximum rate the wells will accept for one month and then production tested up to 50 b/d of oil and 50 b/d of water.

LLOYDMINSTER AREA HEAVY OIL DEPOSITS

General Comments

The Lloydminster accumulations underlie an area of some 5,000 square miles along the Alberta-Saskatchewan border. Reserves may be rather miniscule in comparison to the oil sands. However, because secondary recovery operations are further advanced, they are of importance to producers in the area. Total oil reserves in place are in the three billion barrel range while recoverable reserves utilizing present technology are estimated at 240 million barrels or 8%. Accumulated production as of December 31, 1972 was 120 million barrels. Enhanced recovery

schemes may yield an additional 40% of the oil in place or about one billion barrels. These finds produce by conventional methods, i.e. the wells are cased and the oil is mechanically pumped to the surface. Initial daily rates vary between 20 and 75 barrels although some wells have tested as high as 200 barrels per day. Output may decline to about 10 barrels per day within five years although enhanced recovery schemes such as waterfloods and in-situ combustion can maintain initial production rates over a much longer period as well as increase the ultimate recovery substantially.

Recent Developments

Commercial exploitation of the heavy oil fields in the Lloydminster area has been pioneered by Husky Oil. In 1963, the Company developed a process of blending approximately 20% natural gas condensate with 80% heavy gravity asphaltic crude oil thereby enabling it to ship the asphaltic crude long distances by pipeline. Husky subsequently constructed a pipeline which interconnects with Interprovincial's oil pipeline south of Lloydminster. Throughput capacity of its system is 50,000 barrels per day of blended crude with present daily rates in the range of 30,000 barrels per day. A second pipeline system, also interconnecting with IPL, was constructed by the Murphy-Canadian Reserve team in 1971. This line has a capacity of some 14,000 barrels per day and is currently averaging close to 10,000 barrels per day.

Husky Oil controls over 50% of the present productive capacity and potential acreage in the Lloydminster area and has increased its production from an average of 800 barrels per day in 1962 to 21,000 barrels per day in 1973. Other major producers in this area include Canadian Reserve and Murphy Oil with production of about 4,000 and 2,000 barrels per day respectively.

FUTURE DEVELOPMENT

Oil Sands

Presently proved mineable reserves in the Alberta Oil Sands are adequate to support 20 to 30 plants of 100-150,000 barrels per day capacity and producing 3 million barrels per day. Ultimately, however, common processing facilities will likely develop with capacities up to 300,000 or 400,000 b/d serving several satellite mines, because of the excessive cost of building integrated facilities on every lease. Up to this rate reserves would not be limiting and no new technology would be required. What is limiting, however, is the availability of capital, equipment, manufacturing facilities, design and other professional services, construction, labour and operating personnel. The magnitude of these factors is indicated by the approximate requirements for a 100,000 barrel per day plant.

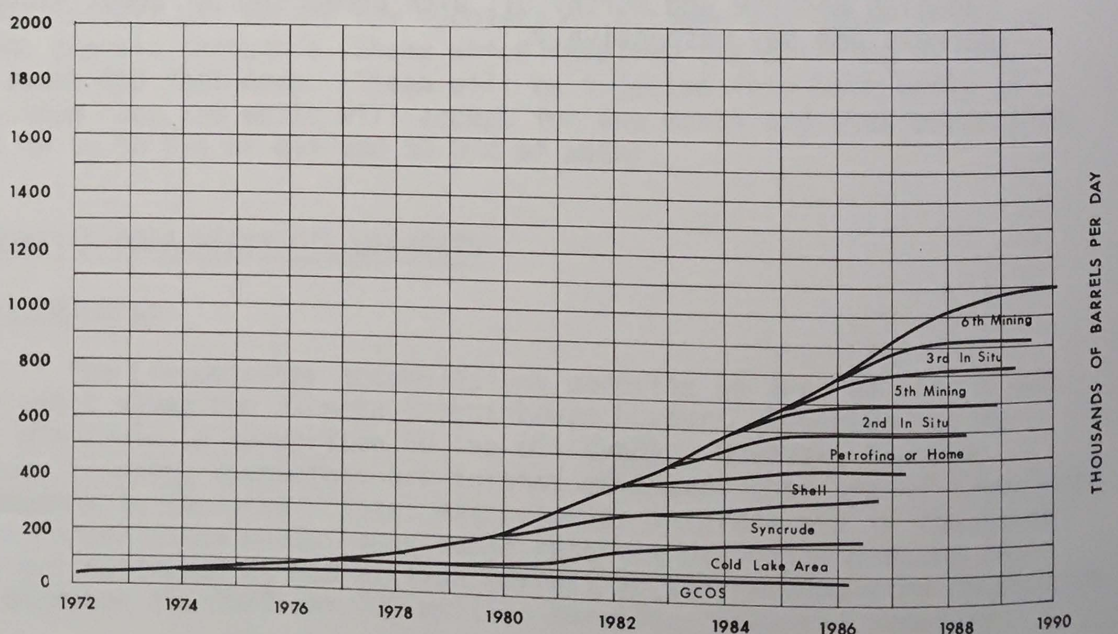
Total capital	800 million 1973 dollars
Specialized equipment	200 million 1973 dollars
Design and professional services	800 man years
Construction labour	5,000 man years
Operating personnel	1,500 men

Furthermore, a substantial lead time from project conception to start of production is necessary - five or six years as well as careful scheduling to avoid conflict with other projects during the actual three to five year construction period.

A forecast of the manner in which synthetic crude oil production may be developed to 1990 is illustrated in Graph 1. Considerable risks are involved in such long range projections; however, a goal of 650,000 barrels per day by 1985 and 1,100,000 barrels per day by 1990 seems achievable.

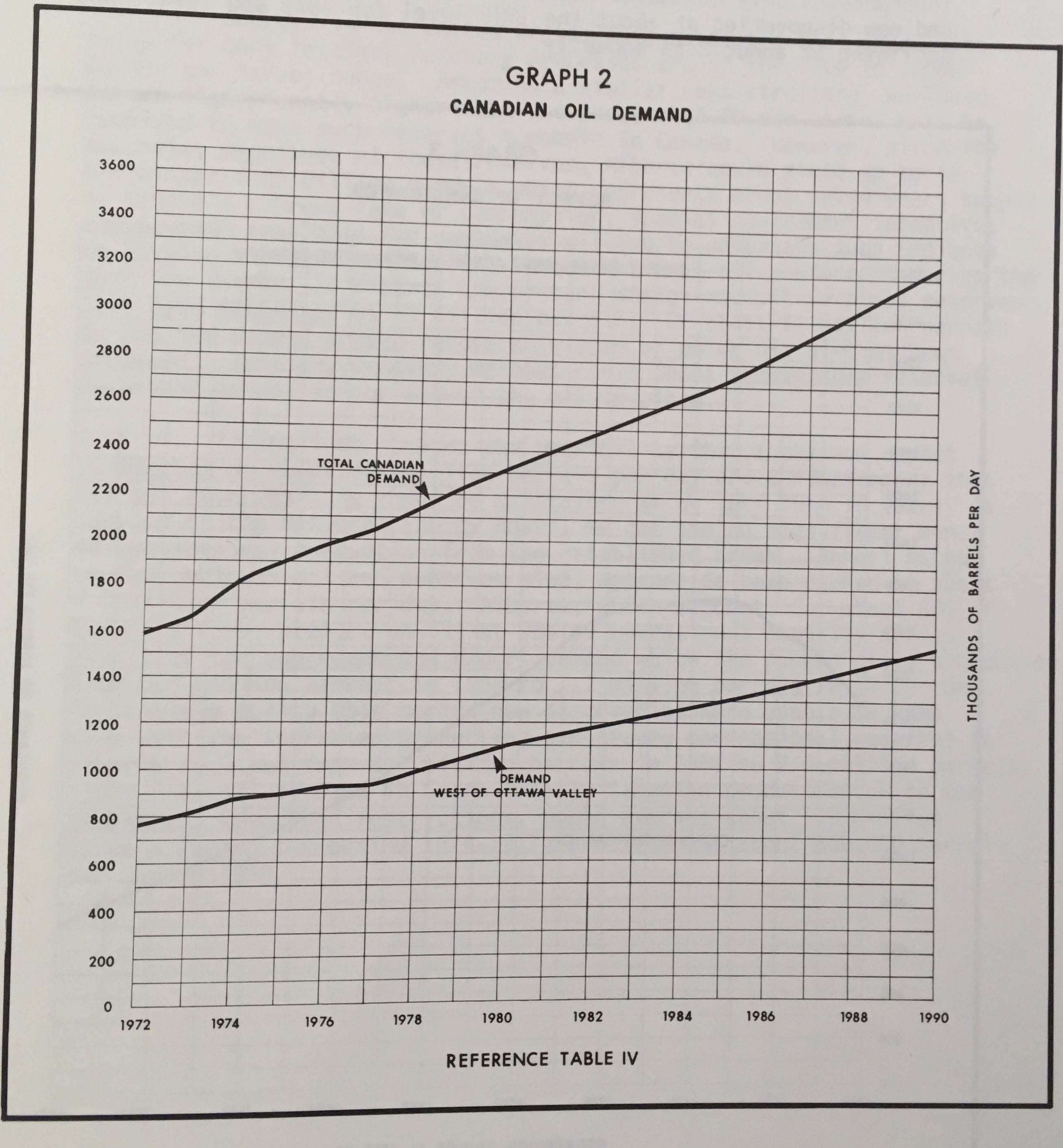
GRAPH 1

SUPPLY OF SYNTHETIC OIL



REFERENCE TABLE III

An assessment of the role of the oil sands in meeting Canada's future petroleum demand as illustrated on Graph 2 would not be complete without reviewing the expected performance of the conventional oil industry as well as the potential of the frontier areas.

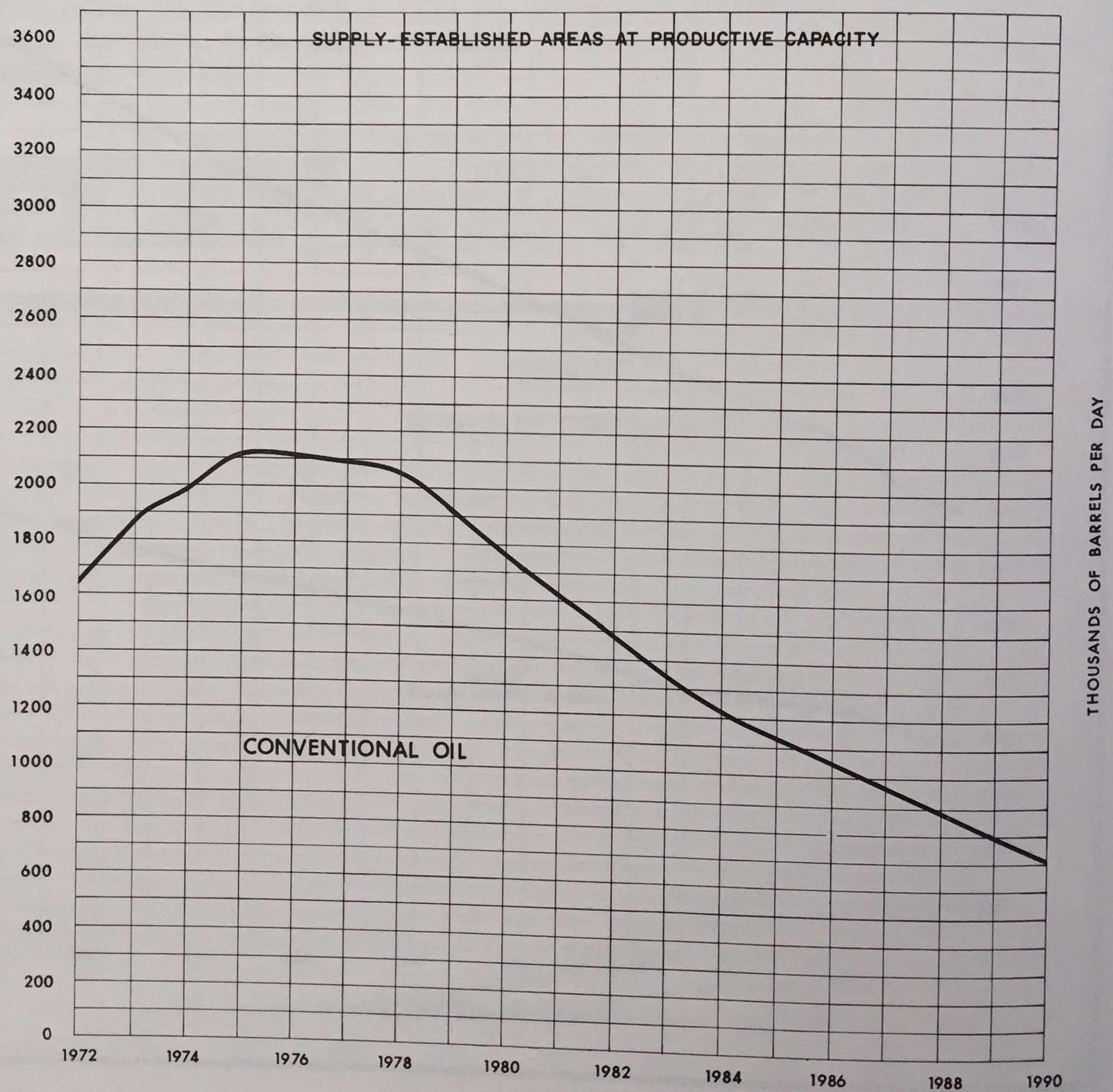


Conventional Oil Supplies

The potential supply of conventional crude from established areas, under limits of productive capacity only, is illustrated in Graph 3; daily production reaches a peak in 1975 at 2.1 million barrels which is sustained until 1978 thereafter declining noticeably. This projection incorporates only estimated reserve additions from revisions, extensions and new discoveries at about the 1972 level for 1973 and 1974, then declining at about 2.5% annually.

GRAPH 3

SUPPLY OF CANADIAN OIL



REFERENCE TABLES V AND VI

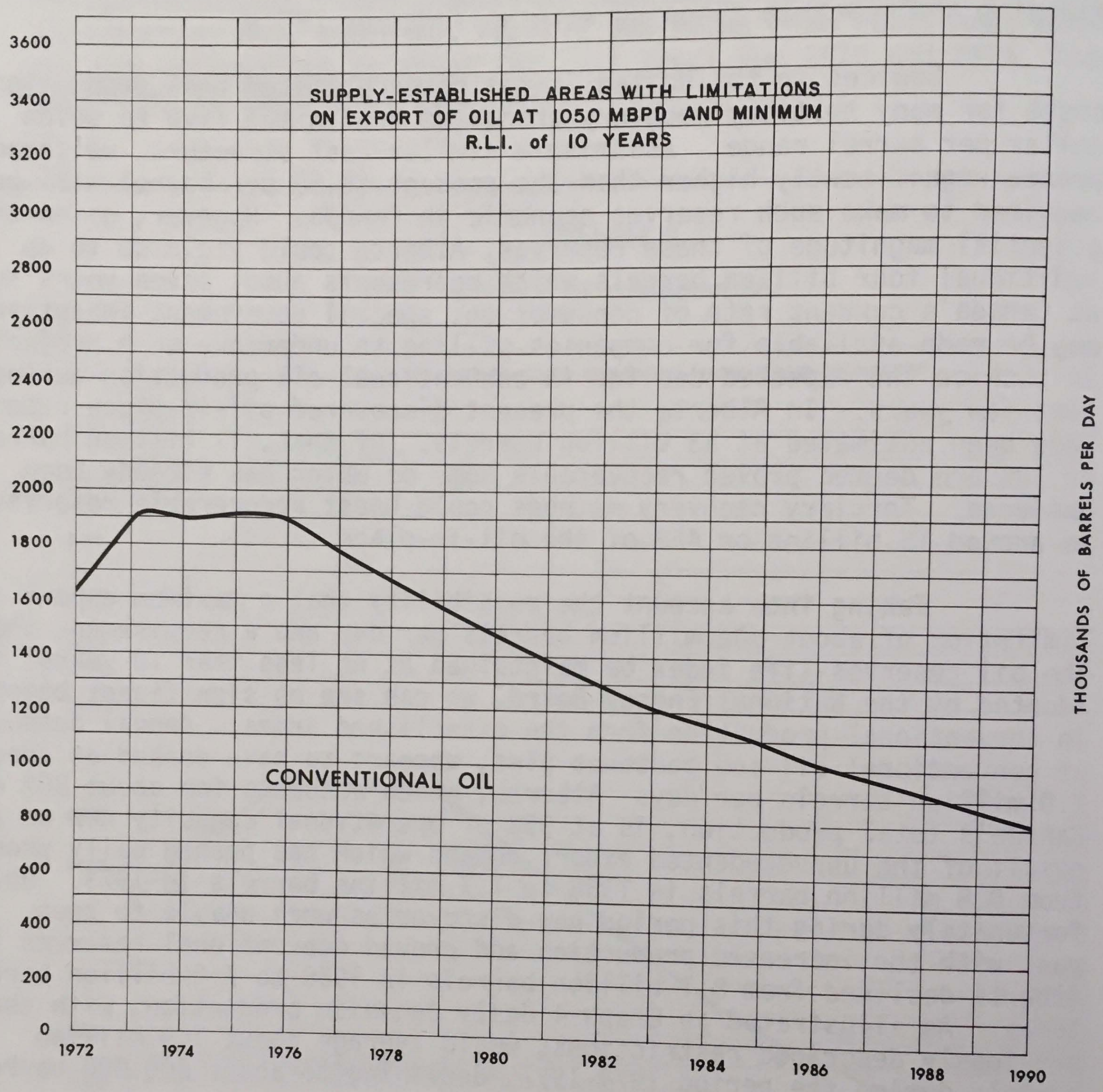
Proved remaining reserves of crude oil equivalent for established areas in Canada as of the end of 1973 were 8.5 billion barrels. See Reference Table V for details. The reserves are the Canadian Petroleum Association (CPA) estimates. These do not include so-called "tertiary" reserves which may be recoverable by the application of some of the more exotic methods of enhanced recovery, e.g. in-situ combustion, steam flooding and miscible flooding with solvents or LPG's.

Sources in the United States have estimated that production costs for many tertiary recovery processes are in the five to seven dollar per barrel range. Assuming a similar cost structure, wellhead prices significantly higher than the present $6.50 per barrel will be required to make such reserves economic in Canada. However, given the potential magnitude of these reserves, Alberta could yield up to an additional four billion barrels which represents about seven years supply at Canada's current rate of consumption; special government incentives may be made available for companies willing to undertake such projects to cushion the expected decline in conventional oil production during the next few years. In Alberta the present discovered oil-in-place reserves have been estimated at 33 billion barrels. Of that, 11 billion barrels or 33% are deemed proved recoverable some of which has already been produced. Tertiary recovery methods could boost recoverable reserves to around 15 billion or 45% of the oil-in-place.

Taking into account the possibility that a maximum export limitation of about one million barrels per day and a requirement that the oil reserves-life index be maintained at no less than 10 years, is adopted by the National Energy Board, we can see no significant boost in conventional production from the established areas. Annual output of conventional oil and pentanes plus, appears to have peaked at about 2.0 million barrels per day. Alberta, which accounts for about 80% of Canada's total production, is at 95% of operational capacity now as a result of the unprecedented export demand which has pushed daily production from 0.8 million barrels in 1968 to 1.7 million barrels in 1973. Unfortunately during this period new discoveries were unable to keep pace with the increased production and proved conventional reserves in Alberta declined from 8.1 billion barrels in 1968 to 7.6 billion barrels today. As illustrated in Graph 4 daily Canadian production, with the previously described restrictions, would average about 1.9 million barrels during the period 1974-1977, declining to about 800,000 barrels per day in 1990.

GRAPH 4

SUPPLY OF CANADIAN OIL



REFERENCE TABLES V AND VI

Frontier Oil Supplies

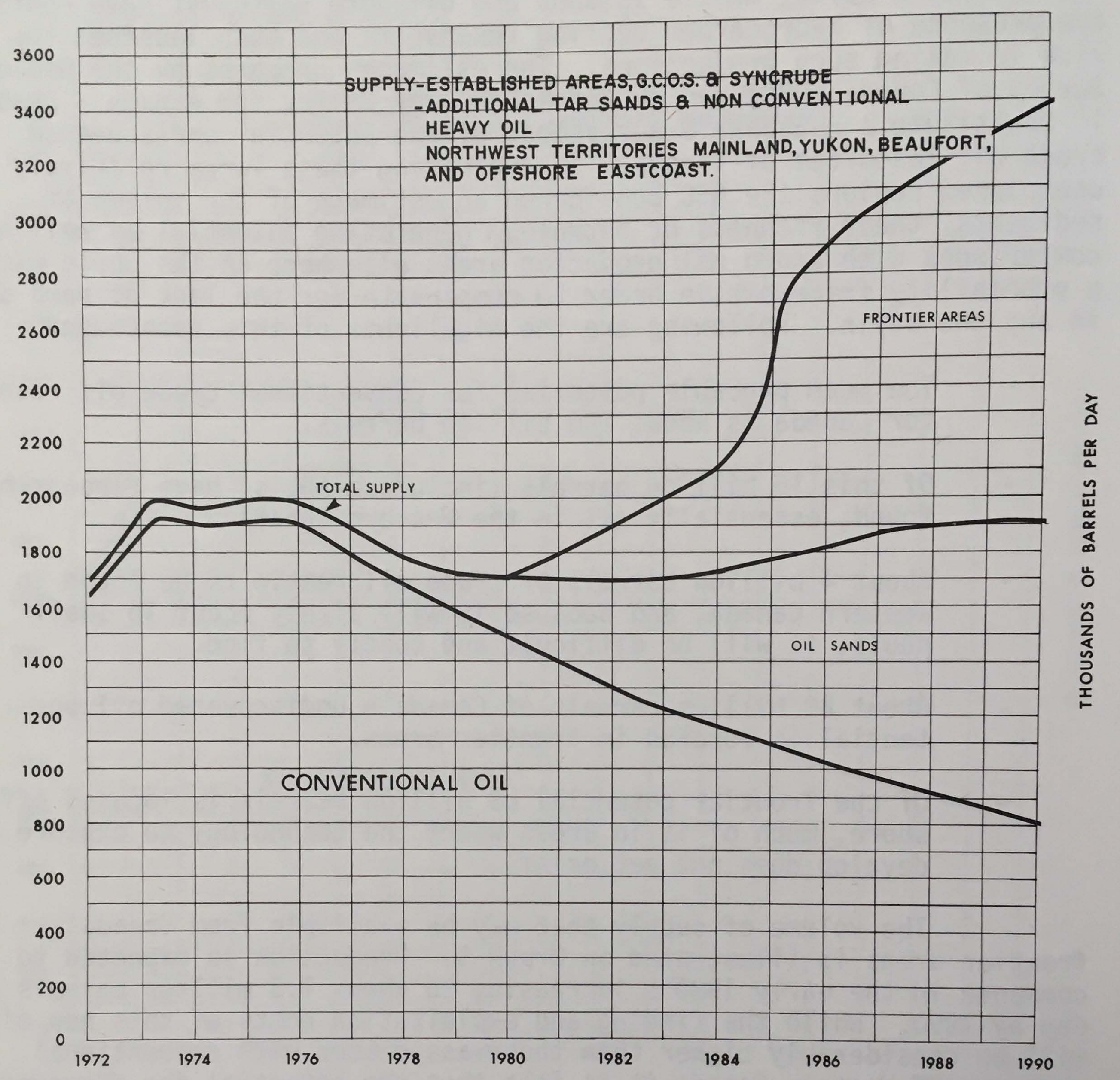
An assessment of the petroleum potential of the Canadian frontier areas is highly speculative at this time because of the limited geological knowledge available. However, initial drilling results in the Mackenzie Delta, Arctic Islands and Offshore Eastcoast have confirmed the presence of hydrocarbon bearing reservoirs and thus lessened the risk in making such projections. The estimates prepared by the Geological Survey of Canada (GSC) and quoted in "Energy Policy for Canada - Phase 1" constitute a reasonable assessment of the potential undiscovered crude oil resources of Canada. In evaluating these large relatively unexplored regions the GSC considered an estimate of the volume of sediments, their richness or petroleum generating potential as well as comparisons with known oil producing areas elsewhere in the world within a probability framework in order to compensate for the lack of hard data in any one basin. Following are the highlights of this assessment:

- The mean probable potential for conventional crude oil resources for Canada is about 100 billion barrels.
- Of this 16 billion barrels (including NGL's) have already been found, essentially all in the Western Canadian basin.
- About 4 billion barrels of crude oil remain to be found in Western Canada, and because it will likely occur in small pools, it will be difficult and costly to find.
- About 80 billion barrels of Canada's undiscovered oil potential is located in frontier areas.
- Of the frontier potential 63 billion barrels is located offshore, much of it in areas where the technology to explore and develop does not yet exist.

The volume of supply that may be available from Canada's frontier areas is illustrated on Graph 5. Production is expected to commence in the early 1980's increasing to about 1.5 million barrels per day by 1990. While the finding and exploitation costs of this new oil will be considerably higher than those associated with conventional reserves of Western Canada it is felt that the potential for discovery of large reserves, high productivity fields will make these operations economically viable. First production is expected to come from the offshore Eastcoast, most likely the Nova Scotia shelf where several oil discoveries have been made to date, with the Mackenzie Delta, on and offshore, having an impact by the mid-1980's.

GRAPH 5

SUPPLY OF CANADIAN OIL



REFERENCE TABLES III, V AND VI

ECONOMICS OF OIL SANDS PRODUCTION

General Comments

Our economic analysis summarized in Table VII is based on project capital and operating cost data available from the Syncrude, Shell Canada, Petrofina Canada and Home Oil applications to the Board as well as the Great Canadian Oil Sands 1973 annual report and supplementary information filed with the Alberta government.

Development Schedule

We have assumed that detailed engineering activities, including pilot plant operations and project design have been completed and field construction would begin in 1974 with preliminary plant operations commencing in 1978.

Economic Parameters

(1) Project life

The economics are based on a facility producing approximately 125,000 barrels of synthetic crude per day for 25 years.

(2) Products and Prices

We assume that two saleable products, 30 degree API gravity synthetic crude and elemental sulphur are produced. The numerous unpredictable factors influencing world oil markets put any price projection at risk. However, we have made the following assumptions:

- Synthetic crude will have access to the world commodity price for crude oil.
- Today's synthetic crude price of $7.00 per barrel will escalate on the average at 5% annually to 1998 when it reaches $22.58 per barrel and then remains constant for the balance of the project life.

No net income has been assumed from the sale of sulphur which would be produced at a daily rate of about 800 tons.

(3) Royalty

With respect to Alberta government involvement we have assumed a similar arrangement to the Syncrude agreement whereby the Province is a joint venture participant and in return for its interest in the leases and leased substances, is to receive 50% of the pre-tax profits remaining after deducting from total revenues each year:

1. Operating Costs
2. Depreciation or recovery of capital
3. An allowance for capital employed equivalent to 6% on total capital employed.

The province, through the Alberta Energy Company, also has an irrevocable option to acquire up to a 20% interest in the Syncrude project up to the commencement of production.

(4) Income Taxes

Federal income tax is payable starting in the sixth year of production and has been calculated at a rate of 40% of net profits after deduction of Alberta's 50% share of profits. A commitment to this effect regarding the Syncrude joint venture was received from the Federal government in December, 1973, and has been confirmed recently by the Finance Minister. Even if the budget proposals should be re-introduced the federal tax system will provide additional tax incentives for development of the oil sands. These measures apparently ensure that total net production revenues from such projects would equal original investment before any federal income taxes become payable. The substantial investment in the original recovery and processing facilities would also earn depletion in a manner similar to exploration and development expenditures.

(5) Operating Costs

The average annual operating costs are estimated to be $105 million at the start-up in 1978 increasing to about $400 million in the final year of the project.

(6) Capital Costs

Based on detailed engineering design estimates, total pre-production expenditure requirements are estimated at about one billion dollars as of December 31, 1977. The industrial components of this cost estimate are as follows:

	$ Million
Mining	300
Extraction, Froth Treatment and Diluent Recovery	150
Upgrading	250
Utilities and Offsites	100
Working Capital	50
Preparation and Miscellaneous Cost	50
Construction Interest	100
Total	1,000

Additional expenditures for extension and relocation of the mining transportation system and for equipment replacement amount to about $290 million during the project's 25 year life.

(7) Escalation

Inflation and other economic factors are expected to cause both the project costs and product prices to escalate with time. Based on historical average escalations for capital and operating cost component parts these expenditures are estimated to escalate at about 5% and 4% per year, respectively.

In the absence of any long term historical data that were considered to be representative of future trends, the price of oil was assumed to escalate at 5% annually from $7.00 per barrel in 1974 through to 1998 and remaining flat thereafter.

Conclusions

Three widely accepted measures of value or indices of profitability used by the petroleum industry to evaluate prospective investments are:

Payout Period: this is the length of time required for cash flow to return the initial investment. It simply tells management how long the investment will remain unrecovered and therefore, at risk. Historically a general rule for acceptability of a project was two to three years especially among independent operators with limited working capital. However, major oil companies having adequate funds are more concerned with continuity of long term operation.

Profit After Payout Per Dollar Invested: this gives consideration to the potential magnitude of ultimate cash flow from a project but it gives no regard to the timing of income received.

Discounted Rate of Return: this is the percentage of the unamortized investment which can be considered as profit from each year's cash operating income and still leave amounts that will exactly retire the investment during its economic life. This is calculated by finding the discount factor which yields a present value of future income equal to the initial investment, i.e. the present value of net cash flow equals zero. Most companies agree that the rate should be around 15% particularly at a time when the return on low risk investments such as good quality bonds is in excess of 10%.

In the case of the oil sands project detailed in Tables VII and VIII the indices are as follows:

Payout period	:	8.3 years
Profit after payout per dollar invested	:	$3.03
Rate of return	:	13%

It is obvious from these figures that the proposed project provides only a minimum return over a long period of time. The risks in forecasting future oil prices coupled with the technological problems which will have to be overcome in the initial years are significant. Companies planning the large expenditures in what must still be considered pioneering ventures are by no means assured to turning a profit and in our opinion the potential returns have been reduced to a minimum acceptable level.

For the large integrated companies the oil sands should ensure a source of supply for their refining and marketing operations and in the case of the major leaseholders offer an opportunity to economize through development of satellite operations in the future.

TABLE 1

HEAVY OIL DEPOSITS OF WESTERN CANADA

PROVED RESERVES AND GENERAL CHARACTERISTICS*

Deposit	Overburden Depth Interval (Feet)	Area Extent (M Acres)	Bitumen Or Heavy Oil In Place (Billion Bbls)	Gravity °API	Sulphur Weight %	Recoverable Crude or Bitumen (MM Bbls*)	Recoverable Synthetic Crude Oil (MM Bbls*)
Athabasca	0-150	490	74			38,000	26,500
	150-250	270	47	6-8			
	150-2000	5,260	506	8-10	5		
Cold Lake A	1000-2000	1,800	118	10-12	3-4		
B	1000-2000	650	33				
C	1000-2000	710	14				
Peace River	1000-2500	1,180	51	9	5		
Wabasca A	250-2000	764	31	7-13	4-5		
B	1000-2500	1,000	23				
Lloydminister	1200-2500	3,200	3	14-16	2-3	240	
TOTALS		15,054	900			38,240	26,500

* Data mainly drived from AERCB Report, December 31, 1973.

M denotes thousands of acres.

MM Bbls denotes millions of barrels.

TABLE II

OIL SANDS PROJECTS DATA SUMMARY

	UNITS	OPERATOR GCOS (1) Initial Plant	Expanded Plant	SYNCRUDE (2)	SHELL (3)	PETROFINA CANADA (4)	HOME OIL COMPANY (5)
Capital Cost Estimate (1973 dollars)	$Million	260		900	710	850	956 (1974 dollars)
Reserves in place	Billion bbls of bitumen.	1.0		2.4	3.7	3.4	1.6
Mining Recovery Factor	%	87		87	88	94	92
Recoverable Reserves	Billion bbls of bitumen.	0.9		2.1	3.3	3.2	1.5
Reserve Life	Years	41	28	41	75	52	29
Oil Sands Mined	* TPCD	93,000	140,000	225,000	200,000	255,000	203,000
Bitumen Recovered	**BPCD	58,000	85,000	140,000	121,000	153,500	123,000
Synthetic Crude Produced	BPCD	45,000	65,000	125,000	100,000	122,500	103,000
Commence - Const.		Sept. 1964		Spring 1974	Jan, 1976	Jan, 1978	July, 1978
First Production		Aug. 1967	n.a.	Jan, 1978	Jan, 1980	July, 1982	July, 1982
Full-scale Production		1971		Jan, 1982	Jan, 1982	July, 1984	July, 1985
CALCULATED UNIT RATIOS							
Capital cost per daily bbl of synthetic production (1973 dollars)		$5,800	$4,500	$7,000	$7,100	$6,800	$9,282 (1974 dollars)
Bbls of bitumen recovered per ton of oil sand		0.62	0.61	0.62	0.61	0.60	0.61
Bbls synthetic crude recovered per bbl of bitumen		0.78	0.76	0.89	0.83	0.80	0.84
Bbls synthetic crude produced per ton oil sand		0.48	0.46	0.56	0.50	0.48	0.51

* Tons per calendar day

** Barrels per calendar day

(1) Participant - Great Canadian Oil Sands - 100%, however Sun Oil Company owns 96% of the common shares.

(2) Participants - Atlantic Richfield Canada Ltd. - 30%, Canada Cities Service Ltd. - 30%, Imperial Oil Ltd. - 30%, Gulf Oil Canada Ltd. - 10%. The Alberta Government has an option to acquire a 20% working interest in this project at cost.

(3) Participants - Shell Canada Ltd. - 50%, Shell Explorer Ltd. (a wholly owned subsidiary of Shell Oil Company) - 50%.

(4) Participants - Petrofina Canada - 35.3%, Pacific Petroleums - 32.7%, HBOG - 14.6%, Murphy Oil Canada - 10.5%, CanDel Oil - 6.9%.

(5) Participants - Home Oil Company - 87.5%, Alminex Limited - 12.5%.

TABLE III

CANADIAN OIL PRODUCTION FORECAST

(Thousands of Barrels/Day)

Year	Established Reserves Export of oil: 1050 MBPD Minimum R.L.I. for oil: 10 years	Synthetic and Heavy Oil	N.W.T. &Beaufort Sea	East Coast Offshore	Total
1972	1,646	52	3	-	1,701
1973	1,910	52	3	-	1,965
1974	1,885	55	3	-	1,943
1975	1,930	60	3	-	1,993
1976	1,905	65	3	-	1,973
1977	1,780	65	3	-	1,848
1978	1,670	115	3	-	1,788
1979	1,570	155	3	-	1,728
1980	1,475	220	3	100	1,798
1981	1,390	300	3	150	1,843
1982	1,300	400	3	200	1,903
1983	1,220	450	3	250	1,923
1984	1,150	600	3	300	2,053
1985	1,080	675	500	350	2,605
1986	1,015	775	600	400	2,790
1987	955	900	700	450	3,005
1988	900	1,000	800	500	3,200
1989	845	1,050	900	500	3,295
1990	795	1,200	900	500	3,395

Source: Gulf Oil Canada
Imperial Oil
Alberta Energy Resources Conservation Board
Syncrude Canada

TABLE IV

CANADIAN OIL DEMAND FORECAST

(Thousands of Barrels Per Day)

Year	West of Ottawa Valley	East of Ottawa Valley	Total Canadian Oil Demand
1972	776	816	1,592
1973	820	833	1,653
1974	880	950	1,830
1975	900	1,000	1,900
1976	920	1,055	1,975
1977	940	1,120	2,060
1978	990	1,160	2,150
1979	1,050	1.190	2,240
1980	1,100	1,235	2,335
1985	1,300	1,430	2,730
1990	1,550	1,700	3,250

SOURCE: Alberta Energy Resources Conservation Board
Oilweek
Gulf Oil Canada

TABLE V

ESTABLISHED AREAS RESERVES

ORIGINAL IN PLACE, ULTIMATE & REMAINING

AT DECEMBER 31, 1973

Provinces	ORGINAL IN PLACE		ULTIMATE RESERVES		REMAINING RESERVES	
	Proved	Probable*	Proved	Probable*	Proved	Probable*
Crude Oil			(Million Barrels)			
Northwest Territories	500	500	60	90	42	72
British Columbia	1,250	1,260	435	480	205	251
Alberta	33,352	33,912	11,369	12,423	6,784	7,839
Saskatchewan	9,605	9,912	1,889	2,066	589	766
Manitoba	667	680	145	167	44	66
Ontario	187	194	61	63	10	13
Other Eastern Canada	18	18	1	2	-	2
Total Canada	45,579	46,476	13,960	15,291	7,674	9,008
Natural Gas Liquids						
British Columbia			61	63	40	41
Alberta			2,314	2,501	1,547	1,734
Saskatchewan			27	29	8	10
Total Canada			2,402	2,593	1,595	1,785
Approximately 50% of the natural gas liquids are C5 plus; thus, the oil and equivalent reserves are:					8,471	9,901

* Includes proved reserves.

Source: CPA Reserves Committee

TABLE VI

ESTABLISHED AREAS RESERVES AND PRODUCTION FORECAST

CRUDE OIL AND PENTANES PLUS

Year	Reserves (MM Bbls.)* Additions	Original	Remaining (1)	Remaining (2)	Production (1) Daily (M Bbls*)	Production (1) Annual (MM Bbls.*)	Reserve Life Index	Production (2) Daily (M Bbls*)	Production (2) Annual (MM Bbls.*)	Reserve Life Index
1972	199	15,675	8,764	8,764	1,646	602	15(Years)	1,646	601	15
1973	249	15,924	8,316	8,316	1,910	697	12	1,910	697	12
1974	247	16,171	7,846	7,875	1,965	717	11	1,885	688	11
1975	235	16,405	7,304	7,406	2,131	777	9	1,930	704	11
1976	226	16,632	6,750	6,937	2,131	780	9	1,905	695	10
1977	214	16,846	6,194	6,501	2,111	770	8	1,780	650	10
1978	205	17,051	5,645	6,096	2,065	754	7	1,670	610	10
1979	198	17,249	5,147	5,721	1,906	696	7	1,570	573	10
1980	190	17,439	4,694	5,373	1,759	643	7	1,475	538	10
1981	182	17,621	4,285	5,048	1,621	591	7	1,390	507	10
1982	168	17,789	3,905	4,741	1,500	548	7	1,300	475	10
1983	161	17,950	3,561	4,457	1,381	505	7	1,220	445	10
1984	153	18,103	3,252	4,190	1,262	462	7	1,150	420	10
1985	146	18,249	2,981	3,942	1,143	417	7	1,080	394	10
1986	140	18,389	2,740	3,712	1,043	381	7	1,015	370	10
1987	125	18,514	2,520	3,488	947	345	7	955	349	10
1988	123	18,637	2,327	3,282	864	316	7	900	329	10
1989	117	18,754	2,157	3,091	786	287	8	845	308	10
1990	114	18,868	2,010	2,915	715	261	8	795	290	10

* M Bbls denotes thousands of barrels, MM Bbls denotes millions of barrels.
(1) No restrictions on exports.
(2) Export of oil limited to 1050 MBPD plus minimum RLI of 10 years.

Source: Gulf Oil Canada

TABLE VII

FORECAST OF OIL PRODUCTION, INCOME AND PRESENT WORTH
FOR A 125,000 B/D OIL SANDS MINING PROJECT
OIL PRICE $7.00/BBL. ESCALATING 5%/YEAR

Year	Capital Expenditures: Beginning of Year $MM	Capital Expenditures: Additions $MM	Capital Expenditures: End of Year $MM	Production: Daily 000's Bbls.	Production: Annual Mill. Bbls.	Synthetic Crude Price $/Bbl.	Revenue $MM	Operating Costs $MM	Amortization of Capital $MM	Interest Allowance $MM	Profit (Loss) $MM	Loss Carried Forward $MM	Profits to be Shared $MM	Alta. Gov't. 50% Interest $MM	Net Profit Before Tax $MM	Net Profit (1) $MM	Total Cash Flow (2) $MM	Additional Capital Expenditures $MM	Prod. Loan Repayment (3) $MM	Net Cash Flow $MM	Present Value Cash Flow @ 15%
1974						7.00															
75						7.35															
76						7.72															
77						8.10															
78	991.7	30.9	1022.6	50	18.3	8.51	155.7	105.7		57.1	(7.1)	7.1					50.0	30.9	17.2	1.9	1.0
79		5.8	1028.4	90	32.9	8.93	293.8	124.8		55.9	113.1		106.0	53.0	53.0	53.0	108.9	5.8	92.8	10.3	4.8
80		6.4	1034.8	105	38.3	9.38	359.3	136.3		54.0	169.0		169.0	84.5	84.5	84.5	138.5	6.4	118.9	13.2	5.3
81		11.7	1046.5	105	38.3	9.85	377.3	143.3		52.3	181.7		181.7	90.9	90.8	90.8	143.1	11.7	118.3	13.1	4.6
82		35.1	1081.6	115	42.0	10.34	434.3	149.6		51.4	233.3		233.3	116.6	116.7	116.7	168.1	35.1	119.7	13.3	4.1
83		52.0	1133.6	120	43.8	10.85	475.2	158.0	56.5	51.6	209.1		209.1	104.6	104.5	62.7	212.6	52.0	144.5	16.1	4.0
84		2.6	1136.2	125	45.6	11.40	519.8	164.8	56.8	50.7	247.5		247.5	123.7	123.8	74.3	181.8	2.6	161.3	17.9	3.8
85		5.7	1141.9	125	45.6	11.97	545.8	174.8	57.1	48.4	265.5		265.5	132.8	132.7	79.6	185.1	5.7	161.5	17.9	3.3
86		-	1141.9	125	45.6	12.57	573.2	184.6	57.1	46.0	285.5		285.5	142.7	142.8	85.7	188.8	-	57.5	131.3	21.3
87		19.0	1160.9	125	45.6	13.20	601.9	192.7	58.3	44.0	306.9		306.9	153.5	153.4	92.0	194.3	19.0		175.3	26.6
88		1.8	1162.7	125	45.6	13.86	632.0	202.1	58.5	41.9	329.5		329.5	164.7	164.8	98.9	199.3	1.8		197.5	26.1
89		25.1	1187.8	125	45.6	14.56	663.9	213.7	60.3	40.1	349.8		349.8	174.9	174.9	104.9	205,3	25.1		180.2	20.7
90		1.3	1189.1	125	45.6	15.28	696.8	223.4	60.3	38.1	375.0		375.0	187.5	187.5	112.5	210.9	1.3		209.6	20.9
91		5.0	1194.1	125	45.6	16.04	731.4	237.4	60.8	35.5	397.7		397.7	198.9	193.8	119.3	215.6	5.0		210.6	18.3
92		6.1	1200.2	125	45.6	16.85	768.4	248.3	61.3	33.0	425.8		425.8	212.9	212.9	127.7	222.0	6.1		215.9	16.3
93		11.7	1211.9	125	45.6	17.69	806.7	260.5	62.5	30.7	453.0		453.0	226.5	226.5	135.9	229.1	11.7		217.4	14.3
94		-	1211.9	125	45.6	18.57	846.8	272.4	62.5	28.2	483.7		483.7	241.8	241.9	145.1	235.8	-		235.8	13.5
95		10.9	1222.8	125	45.6	19.50	889.2	285.0	63.9	25.6	514.7		514.7	257.4	257.3	154.4	243.9	10.9		233.0	11.6
96		1.3	1224.1	125	45.6	20.48	933.9	298.7	64.0	23.0	548.2		548.2	274.1	274.1	164.5	251.5	1.3		250.2	10.8
97		20.8	1244.9	125	45.6	21.50	980.4	312.5	67.5	20.6	579.8		579.8	289.9	289.9	173.9	262.0	20.8		241.2	9.0
98		5.5	1250.4	125	45.6	22.58	1029.6	327.8	68.6	18.2	615.0		615.0	307.5	307.5	184.5	271.3	5.5		265.8	8.7
99		4.3	1254.7	125	45.6	22.58	1029.6	343.5	69.7	15.2	601.2		601.2	300.6	300.6	180.4	265.3	4.3		261.0	7.4
2000		10.4	1265.1	125	45.6	22.58	1029.6	359.3	73.1	12.3	584.9		584.9	292.4	292.5	175.5	260.9	10.4		250.5	6.2
01		13.4	1278.5	125	45.6	22.58	1029.6	376.4	79.9	9.5	563.8		563.8	281.9	281.9	169.1	258.5	13.4		245.1	5.2
02			1278.5	125	45.6	22.58	1029.6	394.5	79.8	6.0	549.3		549.3	274.7	274.6	164.8	250.6	-		250.6	4.7
	991.7	286.8	1278.5		1080.0		17433.8	5890.1	1278.5	889.3	9375.9	7.1	9375.9	4688.0	4687.9	2950.7	5153.2	286.8	991.7	3874.7	272.5

(1) Income tax has been calculated at 40% on pretax profits, however it has been assumed that no tax is payable until total net operating revenue equals original investment. This occurs at the end of the fifth year of production. No allowance has been made for depletion which the original recovery and processing facilities may earn.

(2) Total cash flow is equal to net profit plus amortization of capital (depreciation) and the interest allowance.

(3) Repaid from 90% of cash flow.

TOTAL DISCOUNTED CASH FLOW = 272.5
PRESENT VALUE PER BARREL = 25.2 CENTS
AVERAGE CRUDE PRICE = $16.14/Bbl.
AVERAGE PROFIT PER BBL = $2.73

TABLE VIII

RATE OF RETURN CALCULATION

YEAR	INITIAL INVESTMENT $MM	TOTAL CASH FLOW $MM	ADJUSTED CASH FLOW $MM	PRESENT VALUE $MM 10%	PRESENT VALUE $MM 15%
1974	150.0	-	(150.0)	(143.0)	(139.9)
75	200.0	-	(200.0)	(173.4)	(162.2)
76	350.0	-	(350.0)	(275.8)	(246.9)
77	291.7	-	(291.7)	(209.0)	(178.9)
78	30.9	50.0	19.1	12.4	10.2
79	5.8	108.9	103.1	61.0	47.8
1980	6.4	138.5	132.1	71.1	53.3
81	11.7	143.1	131.4	64.3	46.1
82	35.1	168.1	133.0	59.2	40.6
83	52.0	212.6	160.6	64.9	42.6
84	2.6	181.8	179.2	65.9	41.4
85	5.7	185.1	179.4	60.0	36.0
86	-	188.8	188.8	57.4	32.9
87	19.0	194.3	175.3	48.4	26.6
88	1.8	199.3	197.5	49.6	26.1
89	25.1	205.3	180.2	41.1	20.7
1990	1.3	210.9	209.6	43.5	20.9
91	5.0	215.6	210.6	39.7	18.3
92	6.1	222.0	215.9	37.0	16.3
93	11.7	229.1	217.4	33.9	14.3
94	-	235.8	235.8	33.4	13.5
95	10.9	243.9	233.0	30.0	11.6
96	1.3	251.5	250.2	29.3	10.8
97	20.8	262.0	241.2	25.7	9.0
98	5.5	271.3	265.8	25.7	8.7
99	4.3	265.3	261.0	22.9	7.4
2000	10.4	260.9	250.5	20.0	6.2
01	13.4	258.5	245.1	17.8	5.2
02	-	250.6	250.6	16.5	4.7
	1278.5	5153.2	3874.7	229.5	(156.7)

(1) Payout period = $8 + \frac{57.5}{195.0} = 8.3$ years

(2) Profit after payout per $ invested $\frac{\$3874.7}{1278.5} = \$3.03$ per $ invested

(3) Rate of return = $10\% + (\frac{229.5}{386.2} \times 5\%) = 13.0\%$

TABLE IX

HEAVY OIL LEVERAGED COMPANIES (1)

Canadian Oils	Shares Outstanding (000's)	1973 Net Oil ngl's prod'n (bbls/day)	DSH&P Estimated Gross-in-Place Heavy Oil Reserves (2) (million barrels) — Athabasca: Potential Mining Areas (3) 150' of overburden	Athabasca: In-situ Areas 500' of overburden	Cold Lake: Massive Sand Area	Cold Lake: Other Areas	Peace River	Wabasca	Lloydminster	DSH&P Estimated Heavy Oil Production Potential to 1990 — Barrels Per Share	Daily Mining	In-situ	Annual (000's)	Bbls/Share	Net Earnings Per Share @ $2.73/bbl Net Profit
Integrated															
BP Canada	21,004	25,700	5,400	-	10,000	N.A.	-	N.A.	-	733	50,000	50,000	36,500	1.7	4.64
Gulf	45,493	125,000	1,800	4,000	-	N.A.	N.A.	N.A.	-	127	20,000	-	7,300	.2	.55
Husky	11,502	44,000	-	-	2,000	N.A.	-	-	2,000	348	-	40,000(4)	14,600	1.3	3.55
Imperial Oil	130,117	275,000	5,500	38,000	33,000	N.A.	N.A.	-	-	588	60,000	100,000	58,400	.4	1.09
Murphy	6,274	7,900	800	-	-	N.A.	-	-	N.A.	128	13,000	5,000(4)	6,570	1.0	2.73
Pacific	21,323	53,800	4,000	1,000	-	N.A.	-	-	-	234	50,000	-	18,250	.9	2.46
Petrofina	9,975	29,900G	2,700	-	-	-	-	N.A.	-	271	43,000	-	15,695	1.6	4.37
Shell Canada	91,007	94,100G	3,400	8,400	-	-	3,000	-	-	163	50,000	50,000	36,500	.4	1.09
Texaco Canada	9,715	41,300G	-	8,000	-	N.A.	-	-	-	823	-	-	-	-	-
Total	12,784	6,600G	-	-	-	-	-	-	-	-	-	-	-	-	-
Union	14,396	34,500	1,500	-	-	-	N.A.	-	-	104	40,000	-	14,600	1.0	2.73
Intermediate															
Aquitaine	20,628	31,600	600	1,500	-	-	-	-	-	102	-	-	-	-	-
Ashland	14,406	22,300	1,500	-	-	-	-	-	-	104	10,000	-	3,650	.3	.82
Cigol	21,644	12,700	-	-	-	2,000	-	-	-	92	-	10,000	3,650	.2	.55
Canadian Superior	8,548	35,800	-	1,000	-	-	-	N.A.	-	117	-	-	-	-	-
Dome	11,218	30,500	-	-	-	-	-	-	-	-	-	-	-	-	-
Great Canadian	28,746	50,000	1,200	-	-	-	-	-	-	42	65,000(6)	-	23,725	.8	2.18
Home	8,142	36,000	2,500	-	-	-	-	-	-	307	45,000(5)	-	16,425	2.0	5.46
Hudson's Bay	18,999	77,900	4,900	-	-	-	-	N.A.	-	258	68,000	-	24,820	1.3	3.55
PanCanadian	31,215	50,600	-	-	-	-	-	-	-	-	-	-	-	-	-
Junior															
Alminex	7,646	7,600	700	-	-	-	-	-	-	92	13,000	-	4,745	.6	1.64
Can-Amera	2,140	Nil	700	-	-	-	-	-	-	327	-	-	-	-	-
Candel	4,177	5,400	500	-	-	-	-	N.A.	-	120	9,000	-	3,285	.8	2.18
Canadian Export	8,169	1,700	100	-	-	-	-	-	-	12	-	-	-	-	-
Canadian Reserve	9,613	6,500	-	-	-	-	-	-	500	52	-	5,000(4)	1,825	.2	.55
Chieftain Development	3,031	Nil	-	-	-	-	N.A.	N.A.	-	396	-	-	-	-	-
Numac	4,326	1,700 Est.	-	10,000	-	-	-	-	-	2,312	-	20,000(5)	7,300	1.7	4.64
Pennant-Puma Oils	2,292	427	-	-	-	N.A.	-	-	-	-	-	-	-	-	-
Weco Development	4,828	966	-	-	-	N.A.	-	-	-	-	-	-	-	-	-
Westcoast Petroleum	7,372	930	-	-	1,300	N.A.	-	-	-	176	-	-			
Yellowknife Bear	4,814	Nil	-	-	650	N.A.	-	-	-	135	-	5,000	1,825	.4	1.09
American Oils															
Amerada Hess	21,661	214,733	5,400	-	-	N.A.	-	-	-	249	-	-	-	-	-
Amoco (Std. Indiana)	69,802	876,712	-	8,000	6,500	N.A.	N.A.	N.A.	-	208	-	50,000	18,250	.3	.82
Atlantic Richfield	46,640	656,400	5,500	38,000	-	-	N.A.	-	-	933	60,000	-	21,900	.5	1.37
Belco Petroleum	7,500	40,547	-	-	-	-	N.A.	-	-	-	-	-	-	-	-
Chevron	169,839		5,000	-	-	-	-	N.A.	-	29	40,000	-	14,600	.1	.27
Cities Service	26,867	227,500	5,500	38,000	-	-	-	-		1,619	60,000	-	21,900	.8	2.18
General American	6,305	28,700	-	-	-	-	-	N.A.		-	-	-	-	-	-
Mobil	101,856	506,000	1,900	-	7,000	N.A.	-	N.A.		87	-	-	-	-	-
Shell Oil	67,365	630,137	3,400	8,400	-	-	3,000	-		220	50,000	50,000	36,500	.5	1.37
Sun Oil	36,834	418,916	1,200	4,000	-	N.A.	-	-		141	-	-	-	-	-
Tenneco	68,235	98,200	-	-	-	-	N.A.	-		-	-	-	-	-	-
Texaco Inc.	271,896	2,290,000	-	23,200	-	N.A.	N.A.	N.A.		85	-	-	-	-	-
Others (3)			2,500	10,000							45,000	20,000	23,725	.1	.27
			68,200	201,500	60,450	2,000	6,000		2,500		791,000	405,000(4)			

NOTES

(1) All figures are based upon gross interests before royalty or direct government participation. In the Syncrude project which is the only scheme to receive final approval to date, the province of Alberta has an option to acquire a 20% working interest at cost up to and including that date which is six months after start of production or December 31, 1982, whichever is the earlier. We expect the option to be exercised and look for similar type arrangements in all future projects with the possibility of a higher level of government participation likely.

(2) Reserves have been estimated on the basis of the respective company acreage positions within the oil sands deposits as mapped by the AERCB in their various oil sands reports.

(3) See Table II for details of mining projects announced to date.

(4) Includes projected Lloydminster area production for Husky, Canadian Reserve and Murphy of 30,000 barrels, 5,000 barrels and 5,000 barrels respectively.

(5) Assuming Home Oil and Numac will reduce their respective interests by 50% before the projects are brought on production.

(6) Includes present oil sands production of about 50,000 barrels.

APPENDIX I

Current Information

	Shares Outstanding	1974 Price Range High	Low	Recent	Dividend	1974 Estimated Earnings/Shr.	Price/Earnings High	Low	Recent
BP Canada	21,007,424	17.75	10.50	10.63	.24	1.80	9.7	5.8	5.9
Husky Oil	9,682,825	23.75	13.38	14.63	.50	3.75	6.3	3.6	3.9
Imperial Oil	130,117,139	42.63	25.00	26.00	.80	2.70	15.8	9.3	9.6
Numac	4,325,566	20.25	7.00	8.13	-	.95 (1)	21.3	7.4	8.6

Past performance

	Price Range High	Low	Dividend	Earnings	Price/Earnings High	Low	Average
1973							
BP Canada	20.87	10.62	.15	1.32	15.8	8.0	11.9
Husky Oil	30.00	18.37	.15	2.17	13.8	8.5	11.2
Imperial Oil	49.50	25.87	.80	1.76	28.1	14.7	21.4
Numac	24.00	12.62	-	.79	30.4 (1)	16.0	23.2
1972							
BP Canada	19.00	11.75	-	.89	21.3	13.2	17.3
Husky Oil	19.50	14.12	.15	1.27	15.4	11.1	13.3
Imperial Oil	50.75	29.50	.60	1.22	41.6	24.2	32.9
Numac	23.75	12.62	-	.72	33.0 (1)	17.5	25.3
1971							
BP Canada	11.87	11.12	-	.75	15.8	14.8	15.3
Husky Oil	19.12	14.00	.15	1.09	17.5	12.8	15.2
Imperial Oil	32.37	18.62	.60	1.10	29.4	16.9	23.2
Numac	13.25	7.00	-	.53	25.0 (1)	13.2	19.1
1970							
BP Canada	-	-	-	.53	-	-	-
Husky Oil	15.50	6.75	.15	.67	23.1	10.1	16.6
Imperial Oil	22.75	14.00	.52 1/2	.85	26.7	16.5	21.6
Numac	10.75	4.50	-	.45	23.9 (1)	10.0	17.0

(1) - Cash Flow Per Share.

APPENDIX II

Bituminous Sands Leases

Athabasca Deposit Only

Lease No.	Acreage	Lessee	Interest
5	5,874	Can-Amera Export Refining Company Ltd.	100%
6	6,440	Petrofina Canada Ltd. Pacific Petroleums Hudson's Bay Oil & Gas Murphy Oil Candel Oil	33.337% 32.713% 14.588% 10.487% 6.875%
7	2,866	Petrofina Canada Ltd. et al	See Lease No. 6
8	1,393	Petrofina Canada Ltd.	See Lease No. 6
9	5,601	Petrofina Canada Ltd.	See Lease No. 6
10	11,227	Sun Oil Company Ltd.	100%
11	2,483	Petrofina Canada Ltd.	See Lease No. 6
12	4,174	Petrofina Canada Ltd.	See Lease No. 6
13	49,872	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
14	4,177	Great Canadian Oil Sands Ltd.	100%
15	2,094	Canadian Export Gas & Oil Ltd.	100%
16	5,824	Mobil Oil Canada Ltd.	100%
17	49,788.2	Canada-Cities Service Ltd. Atlantic Richfield Canada Ltd. Imperial Oil Ltd. Gulf Oil Canada Ltd. 1.	30% 30% 30% 10%
18	49,969.1	Hudson's Bay Oil & Gas Co. Ltd.	100%

1. May be reduced to 7.2% through option agreements with several parties including Can-Amera.

19	18,758.6	Bailey Selburn Oil & Gas Ltd.* Canadian Ashland Exploration Ltd.	50% 50%
20	13,656.8	Bailey Selburn Oil & Gas Ltd.* Canadian Ashland Exploration Ltd.	50% 50%
21	2,584	Mobil Oil Canada Ltd.	100%
22	49,590.97	Canada-Cities Service Ltd. Atlantic Richfield Canada Ltd. Imperial Oil Ltd. Gulf Oil Canada Ltd.	See Lease No. 17
23	36,937	Standard Oil Company of British Columbia Ltd. 2.	100%
24	49,941	Supertest Investments & Petroleum Ltd.**	100%
25	49,964	Union Oil Co. of Canada Ltd. 3.	100%
26	23,506	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
27	49,994	Sun Oil Company Ltd.	100%
28	40,642	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
29	49,721.7	Canada-Cities Service Ltd.	See Lease No. 17
30	37,715	Home Oil Co. Ltd. Alminex Limited	87½% 12½%
31	49,870	Canada-Cities Service Ltd.	See Lease No. 17
32	11,365	Canada-Cities Service Ltd.	See Lease No. 17
33	22,700.75	Petrofina Canada Ltd.	See Lease No. 6
34	9,128.7	Petrofina Canada Ltd.	See Lease No. 6
35	49,904.1	Husky Oil Canada Ltd.	100%
36	12,156.4	Mobil Oil Canada Ltd.	100%

2. 2% overriding royalty to BP Canada. 1.6% overriding royalty to Siebens Oil & Gas.

3. 1.75% overriding royalty to Siebens Oil & Gas.

37	49,750.6	Mobil Oil Canada Ltd.	100%
38	26,339.5	Mobil Oil Canada Ltd.	100%
39	49,742.70	Aquitaine Co. of Canada Ltd. Elf Oil Exploration & Production Canada Ltd.	50% 50%
40	22,054	Imperial Oil Ltd.	See Lease No. 17
41	18,491.40	Canada-Cities Service Ltd.	See Lease No. 17
42	21,728.8	Bailey Selburn Oil & Gas Ltd.*	100%
42A	16,208.6	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
43	49,784.3	Can-Amera Export Refining Co. Ltd. Undisclosed	60% 40%
44	49,775	Texaco Exploration Canada Ltd.	100%
45	49,730.5	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
46	49,750.7	Texaco Exploration Canada Ltd. 4.	100%
47	49,734.7	Texaco Exploration Canada Ltd. 4.	100%
48	46,762.9	Texaco Exploration Canada Ltd. 4.	100%
49	49,726.7	Texaco Exploration Canada Ltd. 4.	100%
50	32,824.40	Total Petroleum Co. of Canada Ltd.	100%
51	49,503	Texaco Exploration Canada Ltd. 4.	100%
52	35,109.4	Atlantic Richfield Canada Ltd.	100%
53	49,418.5	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
54	49,483.3	Atlantic Richfield Canada Ltd. Canada-Cities Service Ltd. Imperial Oil Ltd.	33 1/3% 33 1/3% 33 1/3%
55	26,001.5	Atlantic Richfield Canada Ltd.	See Lease No. 54

4. Texaco Inc. owns 100%.

56	23,377	Atlantic Richfield Canada Ltd.	See Lease No. 54
57	49,450.9	Atlantic Richfield Canada Ltd.	See Lease No. 54
58	36,041.5	Atlantic Richfield Canada Ltd.	See Lease No. 54
59	45,413.6	Atlantic Richfield Canada Ltd.	See Lease No. 54
60	31,250.1	Atlantic Richfield Canada Ltd.	See Lease No. 54
61	26,641.4	Atlantic Richfield Canada Ltd.	See Lease No. 54
63	43,562.2	Atlantic Richfield Canada Ltd.	See Lease No. 54
65	49,467.1	Atlantic Richfield Canada Ltd.	See Lease No. 54
66	49,418.6	Atlantic Richfield Canada Ltd.	See Lease No. 54
67	25,968.9	Regent Refining (Canada) Ltd.***	100%
68	46,154.2	Regent Refining (Canada) Ltd.***	100%
69	23,377	Regent Refining (Canada) Ltd.***	100%
70	46,802.2	Atlantic Richfield Canada Ltd.	See Lease No. 54
71	36,492.1	Atlantic Richfield Canada Ltd.	See Lease No. 54
72	41,618.3	Atlantic Richfield Canada Ltd.	See Lease No. 54
73	49,931.2	Amoco Canada Petroleum Co. Ltd.	100%
74	23,352.7	Atlantic Richfield Canada Ltd.	100%
75	25,944.7	Atlantic Richfield Canada Ltd.	100%
76	49,836.7	Amoco Canada Petroleum Co. Ltd.	100%
77	6,086.1	Wood Oil Company Canadian Rhoades Oil Ltd.	

78	36,086.1	Canada-Cities Service Ltd.	See Lease No. 17
79	27,265	Atlantic Richfield Canada Ltd.	See Lease No. 54
81	41,954.4	Atlantic Richfield Canada Ltd.	See Lease No. 54
82	48,588.9	Petrofina Canada Ltd.	See Lease No. 6
84	49,378.5	Sun Oil Co. Ltd.	100%
85	49,418.8	Sun Oil Co. Ltd.	100%
86	4,521.91	Sun Oil Co. Ltd.	100%
87	49,426.9	Tenneco Oil & Minerals Ltd.	100%
88	28,438	Amerada Minerals Corp. of Canada Ltd.	100%
89	14,937	Amerada Minerals Corp. of Canada Ltd.	100%
90	2,916	Amerada Minerals Corp. of Canada Ltd.	100%
91	36,382	Union Oil Co. of Canada Ltd.	100%

* Pacific Petroleums
** BP Canada Limited
*** Texaco Canada Limited

APPENDIX III

Oil Sands Leases

Cold Lake, Peace River & Wabasca Deposit

Lease No.	Acreage	Lessee	Interest
1	41,287.0	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
2	49,402.6	Union Oil Co. of Canada Ltd. Atlantic Richfield Canada Ltd. Canada-Cities Service Ltd. Imperial Oil Ltd.	25% 25% 25% 25%
3	16,840.6	Union Oil of Canada Ltd.	See Lease No. 2
4	49,402.3	Atlantic Richfield Canada Ltd. Canada-Cities Service Ltd. Imperial Oil Ltd.	33 1/3% 33 1/3% 33 1/3%
5	49,402.7	Atlantic Richfield Canada Ltd.	See Lease No. 4
6	49,362.5	Atlantic Richfield Canada Ltd.	See Lease No. 4
7	39,529.5	Atlantic Richfield Canada Ltd.	See Lease No. 4
8	19,456.8	Atlantic Richfield Canada Ltd.	See Lease No. 4
9	49,410.7	Atlantic Richfield Canada Ltd.	See Lease No. 4
10	27,257.0	Atlantic Richfield Canada Ltd.	See Lease No. 4
11	7,768.2	Atlantic Richfield Canada Ltd.	See Lease No. 4
12	20,122.8	Atlantic Richfield Canada Ltd.	See Lease No. 4
13	11,666.4	Atlantic Richfield Canada Ltd.	See Lease No. 4
14	39,010.0	Atlantic Richfield Canada Ltd.	See Lease No. 4

15	41,610.3	Atlantic Richfield Canada Ltd.	See Lease No. 4
16	49,434.9	Atlantic Richfield Canada Ltd.	See Lease No. 4
17	15,544.1	Atlantic Richfield Canada Ltd.	See Lease No. 4
18	46,802.2	Atlantic Richfield Canada Ltd.	See Lease No. 4
19	38,969.8	Atlantic Richfield Canada Ltd.	See Lease No. 4
21	46,842.8	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
22	7,768.0	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
23	4,540.2	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
24	4,688.1	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
25	7,120.2	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
26	8,752.3	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
29	49,882.5	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
30	10,532.4	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
33	14,613	Amoco Canada Petroleum Co. Ltd.	100%
34	22,089	Amoco Canada Petroleum Co. Ltd.	100%
35	18,809	Canadian Homestead Resources Ltd. Texaco Exploration Canada Ltd.	
36	23,205	Amerada Minerals Corp. of Canada	100%
37	11,369	Texaco Exploration Canada Ltd.	100%

38	46,803	Gulf Oil Canada Ltd.	100%
39	28,257	Imperial Oil Ltd.	100%
40	49,603	Imperial Oil Ltd.	100%
41	49,705	Imperial Oil Ltd.	100%
42	49,739	Imperial Oil Ltd.	100%
43	10,375	Petrofina Canada Ltd.	100%
44	7,444	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
45	46,470	Mobil Oil Canada Ltd.	100%
46	48,587	Mobil Oil Canada Ltd.	100%
47	38,002	Mobil Oil Canada Ltd.	100%
48	38,166	Mobil Oil Canada Ltd.	100%
49	16,192	Imperial Oil Ltd.	100%
50	11,016	Amerada Minerals Corp. of Canada	100%
51	4,528	Amerada Minerals Corp. of Canada	100%
52	40,909	Texaco Exploration Canada Ltd.	100%
53	4,220	Sun Oil Co. Ltd.	100%
54	15,885	Canadian Industrial Gas & Oil Ltd. Supertest Investments & Petroleum Ltd.* Hanna Oil Development Co. Donald Breck Lamont United Canso Oil & Gas Ltd.	50% 22½% 12½% 12½% 7½%
55	7,116	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
56	7,456	Union Texas of Canada Ltd.	100%
57	7,456	Union Texas of Canada Ltd.	100%
58	11,508	Mobil Oil Canada Ltd.	100%
59	49,907	Home Oil Co. Ltd.	100%

60	16,393	Canadian Industrial Gas & Oil Ltd.	100%
61	15,245	BPOG Operations Ltd.*	100%
62	10,848	BPOG Operations Ltd.*	100%
63	22,721	Westcoast Petroleum Ltd.	100%
64	49,411	Triad Oil Manitoba Ltd.*	100%
65	19,801	Kerr-McGee Corp. TransOcean Oil Inc.	
66	36,969	Northern Oil Explorers Ltd.	100%
67	41,457	Amoco Canada Petroleum Co. Ltd.	100%

* BP Canada Limited

APPENDIX IV

Oil Sands Permits

Cold Lake and Peace River Deposits

Permit No.	Acreage	Permittee	Interest
13	45,505	Great Northern Oil Ltd.	100%
14	40,081	Shell Canada Ltd. Shell Explorer Ltd.	50% 50%
15	20,224	Mobil Oil Canada Ltd.	100%
16	17,132	Pacific Petroleums Ltd.	100%

NOTES

(1) All figures are based upon gross interests before royalty or direct government participation. In the Syncrude project which is the only scheme to receive final approval to date, the province of Alberta has an option to acquire a 20% working interest at cost up to and including that date which is six months after start of production or December 31, 1982, whichever is the earlier. We expect the option to be exercised and look for similar type arrangements in all future projects with the possibility of a higher level of government participation likely.

(2) Reserves have been estimated on the basis of the respective company acreage positions within the oil sands deposits as mapped by the AERCB in their various oil sands reports.

(3) See Table II for details of mining projects announced to date.

(4) Includes projected Lloydminster area production for Husky, Canadian Reserve and Murphy of 30,000 barrels, 5,000 barrels and 5,000 barrels respectively.

(5) Assuming Home Oil and Numac will reduce their respective interests by 50% before the projects are brought on production.

(6) Includes present oil sands production of about 50,000 barrels.